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COAL: A CLEAN FUTURE

HEARING

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SUBCOMMITTEE ON ENERGY, NATURAL RESOURCES, AND INFRASTRUCTURE

OF THE

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UNITED STATES SENATE

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CONTENTS

OPENING STATEMENTS

Page

Bingaman, Hon. Jeff, a U.S. Senator from New Mexico, chairman, Subcommittee on Energy, Natural Resources, and Infrastructure, Committee on Finance 1
Thomas, Hon. Craig, a U.S. Senator from Wyoming 2
Kerry, Hon. John, a U.S. Senator from Massachusetts 15

WITNESSES

Waddington, Steve, executive director, Wyoming Infrastructure Authority, Cheyenne, WY 3
French, Dr. Nina, director, Clean Coal Combustion, ADA–ES, Littleton, CO ... 4
Diesch, John, president, Rentech Energy Midwest Corporation, East Dubuque, IL 6
McPherson, Dr. Brian, research scientist, Petroleum Recovery Research Center, New Mexico Tech; and manager, Carbon Engineering Group Energy and Geoscience Institute, University of Utah, Salt Lake City, UT 8
Townsend, Bill, CEO, Blue Source, Holladay, UT 10

ALPHABETICAL LISTING AND APPENDIX MATERIAL

Bingaman, Hon. Jeff:
    Opening statement 1
Diesch, John:
    Testimony 6
    Prepared statement with attachments 31
    "Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context," Toyota Motor Corporation study, November, 2004 64
French, Dr. Nina:
    Testimony 4
    Prepared statement 195
Kerry, Hon. John:
    Opening statement 15
McPherson, Dr. Brian:
    Testimony 8
    Prepared statement 205
Thomas, Hon. Craig
    Opening statement 2
    Prepared statement 217
Townsend, Bill:
    Testimony 10
    Prepared statement 218
Waddington, Steve:
    Testimony 3
    Prepared statement 229

COMMUNICATIONS

Bardin, David J. 235
Clean Air Task Force 240

COAL: A CLEAN FUTURE

THURSDAY, APRIL 26, 2007

U.S. SENATE,
SUBCOMMITTEE ON ENERGY,
NATURAL RESOURCES, AND INFRASTRUCTURE,
COMMITTEE ON FINANCE,
Washington, DC.

The hearing was convened, pursuant to notice, at 1:09 p.m., in room SD–215, Dirksen Senate Office Building, Hon. Jeff Bingaman (chairman of the subcommittee) presiding.

Present: Senators Kerry, Salazar, Hatch, Thomas, and Bunning.

OPENING STATEMENT OF HON. JEFF BINGAMAN, A U.S. SENATOR FROM NEW MEXICO, CHAIRMAN, SUBCOMMITTEE ON ENERGY, NATURAL RESOURCES, AND INFRASTRUCTURE, COMMITTEE ON FINANCE

Senator BINGAMAN. All right. Thank you all for coming. Why don't we go ahead with the hearing? I am sorry we are starting a little late. We were completing a vote over on the Senate floor.

This is a hearing of this new Finance Committee Subcommittee on Energy, Natural Resources, and Infrastructure, and we are very much looking forward to testimony on advanced coal technologies.

As we discuss energy policy and how to best use coal—a natural resource we obviously have in abundance—to enhance our energy security, it is important that we learn more about the feasibility of various advanced clean coal technologies that allow for carbon capture and storage and sequestration.

In our current tax code we have several tax incentives for these technologies. There is an investment tax credit for investments in advanced coal technologies; there is an accelerated depreciation to address capital costs involved with these technologies.

We hope that we will hear in today's testimony about the impact of those and what else is needed. In particular, I think we asked for testimony about clean coal and gasification projects, including the newly-announced Wyoming Coal Gasification Project. It is of particular interest, of course, to Senator Thomas. It is a private/public partnership formed to develop an Integrated Gasification Combined Cycle, or IGCC, power plant, as I understand it.

Also, we need to know more about the coal-to-liquids prospects, also about refined coal production tax credits, and also the cost of establishing new facilities, as well as retrofitting existing coal-fired electric utilities.

We've got a great group of witnesses here to talk to us about these important issues, and obviously figuring out how to effectively capture and sequester carbon is going to be essential as we deal with greenhouse gas emissions and meeting our energy needs in the future. So, thank you all for being here.

Senator Thomas, go right ahead.

STATEMENT OF HON. CRAIG THOMAS, A U.S. SENATOR FROM WYOMING

Senator THOMAS. Thank you, Mr. Chairman. Thank you for holding this hearing. I think it is very important.

I welcome all the witnesses here. I look forward to your comments. I especially want to welcome Steve Waddington, the executive director of the Wyoming Infrastructure Authority, and we are delighted to have you here.

We are all in an environment where we are concerned about the prospects of global climate change, as we should be, and focused on the finite fossil fuels resources, and many are focused on alternative sources. I understand that, and I am looking forward to alternative sources as well.

But I understand that some of those are a ways off, and what we need to do is work on those things that are going to be available to us immediately, and are available, that we know how to do, and to be able to provide the incentives to move forward to making those things available for all of us.

The renewed technologies are not ready for mass development but, by contrast, coal already provides more than 50 percent of our country's electricity. So I think, frankly, coal gets kind of a bad rap. We see those full-paged ads with the dirty faces. I have never seen quite so many ads in my life.

In any event, that kind of reinforces the myth that coal necessarily belches out in harmful amounts. These days we can burn coal cleanly to produce electricity, and we can gasify it, liquify it into diesel, and we can even turn it into plastic or ethanol.

So in any event, I am concerned about carbon emissions, of course, and actually there are other things that are involved in that as well. As humans, we breathe and we emit carbon dioxide ourselves, so I hope we do not have to wear a mask here pretty soon.

In any event, there are a lot of economic benefits to coal, and we are going to hear today about how we might best use it in an environmentally sound way, and I thank you so much for being here.

Thank you, Mr. Chairman.

[The prepared statement of Senator Thomas appears in the appendix.]

Senator BINGAMAN. Thank you very much.

We will go from our left to our right across the table here. Our first witness is Mr. Steve Waddington, who is the executive director of the Wyoming Infrastructure Authority out of Cheyenne. Thank you for being here.

Why don't you go ahead? If each of you could give us 5 to 6 minutes and describe the main points you think we need to be aware of, we will include your full statement in our hearing record, but that will give us a chance to ask a few questions.

So, Mr. Waddington, why don't you go ahead? Then we will hear from all five of the witnesses before we ask questions. But go right ahead.

STATEMENT OF STEVE WADDINGTON, EXECUTIVE DIRECTOR, WYOMING INFRASTRUCTURE AUTHORITY, CHEYENNE, WY

Mr. WADDINGTON. Thank you, Mr. Chairman, for inviting me to appear before you today.

The Wyoming Infrastructure Authority is an instrumentality of the State of Wyoming. Our mission is to diversify and expand the State's economy through improvements in the electric transmission grid and by stimulating advanced coal technology development for electricity production.

My testimony today on "Coal: A Clean Future" is based upon two equally important premises. The first premise is that the United States and other governments will take action to restrict the emission of CO_2 and other greenhouse gases.

The second premise is that coal must, and will, continue to play an indispensable role as a source of energy for the United States, and the world, in our carbon-constrained future.

Government has a crucially important and large role to play to support commercial-scale emergence of advanced coal technologies, including gasification, other technologies that can convert coal to energy while capturing CO_2, and large-scale, permanent sequestration.

Last week, the Wyoming Authority announced a partnership with a major electric utility, PacifiCorp, to develop an Integrated Gasification Combined Cycle commercial demonstration plant.

This will be the first of its kind, an IGCC plant designed and built to use lower-rank western coals at altitude, to include the capture and sequestration of CO_2, and to operate on a long-term commercial basis.

The Wyoming Authority and PacifiCorp are seeking significant Federal financial support, including appropriations for a provision of the 2005 Energy Policy Act, section 413, that authorizes Federal funding for a western goal gasification commercial demonstration. Investment tax credits and other Federal support will also be sought for the Wyoming IGCC plan.

Adequate Federal support for the Wyoming demonstration is but a small step in what is needed nationally. While IGCC is, today, a leading candidate for electricity production with CO_2 capture, it is critically important to demonstrate this and alternative coal combustion and conversion technologies that also can include capture capability. Federal R&D support in this area should be significantly increased.

The sequestration of CO_2 will be a key enabling technology that can reduce emissions significantly and allow coal to continue to contribute to the world's energy needs. Yet, today large-scale geological sequestration is, for the most part, a theory, not a commercial practice.

What is needed is large-scale demonstration of sequestration in multiple geological environments. Here again, continued and increased Federal R&D support is vitally important. There may also be an appropriate Federal role in indemnifying companies for long-term sequestration liability risk.

Congress should also consider tax incentives to encourage the private sector to deploy sequestration. For example, a volumetric tax credit for CO_2 that is permanently stored in a geologic formation or used for enhanced oil recovery could be a significant market-moving incentive.

Adequate transmission infrastructure will also be vital for a clean future using coal. This is especially true in the west, where coal plants can be located at or near mine mouth, producing electricity that is shipped by wire to load centers.

The institutional impediments to adequate transmission investment go beyond the scope of this hearing, but suffice it to say that many western States recognize this as a profound problem and are taking proactive measures to address it.

In 2004, Wyoming created the Infrastructure Authority with tools to catalyze transmission investment, including $1 billion in bonding capacity. Today, five additional States have joined Wyoming, including most recently, Mr. Chairman, New Mexico, and at least three additional States are actively considering creating State transmission financing authorities.

These western States want to invest in transmission to facilitate energy resource development. Yet, under IRS rules, the bonds for these State entities are not exempt from Federal tax.

I strongly advocate that this subcommittee consider legislation to relax the so-called “private use” restriction and allow State transmission financing entities to issue tax-exempt bonds for interstate infrastructure needs.

This will help to empower States that are trying to make a difference, provide an incentive for needed transmission investment, and ultimately lower costs to end consumers.

This concludes my summary statement, Mr. Chairman. I would be pleased to answer any questions when the time arrives. Thank you very much.

Senator BINGAMAN. Well, again, thank you for being here. Thank you for your testimony.

[The prepared statement of Mr. Waddington appears in the appendix.]

Senator BINGAMAN. Next, is Dr. Nina French. She is the director of Clean Coal Combustion for ADA–ES in Littleton, CO. Thank you very much for being here. Please go right ahead.

STATEMENT OF DR. NINA FRENCH, DIRECTOR, CLEAN COAL COMBUSTION, ADA–ES, LITTLETON, CO

Dr. FRENCH. Chairman Bingaman and members of the subcommittee, it is my privilege to come here today to talk to you about clean coal and how Federal support, both in tax incentives and technology development, are necessary and effective catalysts to stimulate development.

My name is Dr. Nina French. I am the director of Clean Coal Technologies at ADA. We specialize in emissions control from coal-fired power plants, and we have over 30 years of experience in bringing environmental technologies from concept to commercialization, so I can speak firsthand about what it takes to develop new ideas in this industry.

First, everything is big, and the cost of failure is high. I can speak personally to that. Second, electricity is a commodity. The market for anything new is driven by cost and regulation. Third, we have a juggle between regulations and technology, and the timing. You cannot endorse regulations without technology, but it is hard to invest in technology without regulations. Fourth, each coal-fired power plant is different. There is no one-shoe-fits-all solution.

Yet, we have an opportunity. The United States has more coal than any country in the world. We have invested billions of dollars in infrastructure and, as a result, we have reliable, inexpensive electricity.

So our challenge is, how do we develop clean coal that will endure through the next century? We have done a lot already, although it is small compared to what we still have to do.

We started with just boilers and turbines, and then in the 1950s we developed particulate control emissions. In the 1980s and 1990s, regulations motivated us to develop sulfur dioxide (SO_2) control, and nitrogen oxides (NOx) control.

Now mercury control is available. Twelve States have already implemented stringent mercury control. Early on, the industry for mercury control was faced with the same technology regulation hurdle, but Federal support stepped in and made mercury control available for a fraction of predicted costs.

Federal support has also incentivized refined coal. In response to the section 45 tax credit, ADA is developing a pre-combustion treatment to burn Powder River basin coal. This tax credit works because it is goal-oriented, not technology-specific.

It also includes a 50-percent market value test that is workable with legislative clarification. Through this tax incentive, we can provide clean coal technology for smaller, older power plants that might not otherwise stay open.

Our next challenge is carbon. The scale is enormous. Industry agrees on two approaches for reducing carbon. The first is efficiency. If we can increase a coal-fired power plant's efficiency from the current 38 percent to 48 percent, we take 25 percent of the carbon out, that's 25 percent less carbon that we have to store and sequester.

Technologies are available for both new plants and existing plants to improve efficiency, but there is no incentive to spend the extra money. A more efficient plant costs more money, and we need to incentivize adding that additional cost.

The second, longer-term approach that you will hear about from the other witnesses is carbon capture and storage. A number of promising concepts are available, but they are in their infancy, and to develop them will require a massive R&D investment. History tells us the timeframe is probably long—10 to 20 years—but the success is likely.

If we use Federal support to reduce technology risk for coal-fired power plants, the commercial market can, and will, leverage these solutions across the entire 320,000-megawatt industry. This is an incentive, not a subsidy.

To accomplish this, we need your leadership. Recognizing the magnitude of the CO_2 challenge, we need you to consider the following: coordinating incentives such as tax credits and technology development funding with regulations; second, focusing on environmental goals, not specific technologies; and third, drafting clear, enforceable tax credits. Use industry experts if you need to, to help define details such as baselines and improvement metrics, to purposely design what you want.

In closing, I believe that, with a wise and diligent plan, we can trust coal to be a clean source of electricity, now and in the future.

Thank you for your attention.

Senator BINGAMAN. Thank you very much. We appreciate the excellent testimony.

[The prepared statement of Dr. French appears in the appendix.]

Senator BINGAMAN. Next, Mr. John Diesch. Is that the correct pronunciation?

Mr. DIESCH. That is correct.

Senator BINGAMAN. John Diesch, the president of Rentech Energy Midwest Corporation in East Dubuque, IL. Thank you for being here.

STATEMENT OF JOHN DIESCH, PRESIDENT, RENTECH ENERGY MIDWEST CORPORATION, EAST DUBUQUE, IL

Mr. DIESCH. Thank you, Chairman Bingaman, Senator Thomas. My name is John Diesch. I am president of Rentech Energy Midwest, a subsidiary of Rentech. Rentech is a leading U.S. developer of FT fuel plants. FT fuels are ultra-clean synthetic diesel and jet fuels that can be made from coal, petroleum coke, natural gas, and biomass.

I am here today to request your support to, number one, include FT specifically in the investment tax credit; number two, increase the tax credit for carbon capture and sequestration; and three, support long-term contracting authority for the U.S. military, who have expressed great interest in FT fuels.

You should have a sample of the Fischer Tropsch fuels. Do we have that?

Senator BINGAMAN. We do.

Mr. DIESCH. All right. If you want to pull the cap off.

Senator BINGAMAN. Shall we dab it behind our ears? [Laughter.]

Mr. DIESCH. If it smells like wax, it is because it is a paraffin. That is what it is: a paraffin, a wax.

What is unique about it is, it is better for the environment than conventional fuels. It can be used in any diesel engine. Last fall, the Air Force flew a B–52 on the jet fuel version of FT. Our fuel has major advantages over conventional fuels. FT can be made from abundant U.S. sources, cutting our dependence on foreign oil.

FT runs far cleaner than conventional diesel, cutting regulated emissions by up to half. FT is biodegradable and has a shelf life up to 10 times longer than conventional diesel, making it ideal for strategic and military reserves.

When manufacturing is optimized to capture and sequester carbon, FT greenhouse gas emissions—that is wells-to-wheels—is less than conventional diesel and much better than gasoline.

Right now, I manage an ammonia plant in East Dubuque that makes fertilizer from natural gas. Most of our fertilizer goes to corn farmers in Iowa, Illinois, and Wisconsin. Like most U.S. fertilizer plants, we are struggling.

Let me show you the economics. We use 31,800 million Btus per day of natural gas. The U.S. has the highest gas price in the world. A simple 10-cent increase adds $1 million per year to our operating costs.

Do you know that over half the nitrogen fertilizer used to grow our food in the U.S. is now imported because so many U.S. plants have shut down? My plant would have shut down 3 years ago if it were not for converting to clean coal technology.

During that conversion we are also adding an FT fuels plant. Why? Because synthesis gas from coal gasification is the building block for many products, including FT fuels. We will begin construction later this year with an investment approaching $1 billion, and nearly 1,000 construction workers will be employed at the peak of construction. Permanent plant jobs will double. By 2010, we will be making fertilizer from coal in East Dubuque. We will also have the Nation's first commercial-scale FT fuels plant.

Active support from both State and Federal governments is critical to jump starting this industry. We were able to move East Dubuque forward because of help from Illinois. We had hoped to use the provisions of EPAct 2005, including the 48B investment tax credit. That program was capped at $350 million, but applications totaled $2.7 billion. Unfortunately, that meant a lot of great applications like ours got nothing.

From this, we have two recommendations. First, raise the cap on the credit. We strongly recommend a significant increase, at least double. Second, clarify that gasification for FT is included. In fact, we suggest designating a portion of the tax credit for FT projects. Next, fund basic research into promising carbon capture and storage applications that will benefit industries across the board.

In East Dubuque, we already capture carbon. We use some to make the urea fertilizer that we produce. We also capture more as carbon dioxide, CO_2, which is used for food products. Rentech's engineers are working on recycling configurations that maximize the capture of CO_2.

Our proposed Natchez, MS plant is near oil fields where the CO_2 will be used for enhanced oil recovery. It would be helpful to significantly increase the 15-percent tax incentives for companies like Rentech that are taking the lead on carbon capture and sequestration (CCS) and their plant designs. These tax incentives, paired with longer military contracting authority, could set the stage for rapid development of this industry.

I invite you to visit us. We are proud of our products, proud of our workforce, and proud that we are good neighbors to the Mississippi River and the Tri-State region. Thank you very much for your time.

Senator BINGAMAN. Thank you very much. Thanks for your excellent testimony.

[The prepared statement of Mr. Diesch appears in the appendix.]

Senator BINGAMAN. Dr. Brian McPherson is next. He is a research scientist with the Petroleum Recovery Research Center at

New Mexico Tech, and also manager of the Carbon Engineering Group Energy and Geoscience Institute at the University of Utah. Thanks for being here.

STATEMENT OF DR. BRIAN McPHERSON, RESEARCH SCIENTIST, PETROLEUM RECOVERY RESEARCH CENTER, NEW MEXICO TECH; AND MANAGER, CARBON ENGINEERING GROUP ENERGY AND GEOSCIENCE INSTITUTE, UNIVERSITY OF UTAH, SALT LAKE CITY, UT

Dr. MCPHERSON. Thank you. Thank you, Mr. Chairman, Senator Thomas, and other members of the committee. Thanks for the opportunity to testify about potential incentives and barriers associated with carbon capture and sequestration.

My name is Brian McPherson, and I specialize in geology, geophysics, and subsurface hydrology. For the past 10 years, I have served as a professor of hydrogeology at New Mexico Tech, and for the past 3½ years I have served as PI and Director of the Southwest Regional Partnership on Carbon Sequestration, a consortium sponsored by the U.S. Department of Energy, along with six other regional partnerships.

The general premise of geological CO_2 sequestration is to, firstly, separate CO_2 from power plant flue gases, then capture that CO_2 in a separate stream, compress the CO_2 to elevated pressures to maximize its density, and then inject the CO_2 into subsurface geological formations ranging from 2,500- to 20,000-feet depth, and then monitor the fate of that CO_2.

Target storage reservoirs are porous and permeable rock layers overlain by low-permeability confining layers, and such geologic reservoirs contained brine, oil and natural gas for millennia, thus, using these reservoirs for storing CO_2 is a very viable concept.

Target reservoirs are commonly classified by what type of fluid they hold, including depleted oil and gas fields, deep unmineable coal seams, and deep saline formations. With a robust confining layer, sequestration duration can be maximized and risk minimized.

With respect to engineering, such CO_2 injection has been done for decades in many areas of the U.S., primarily for enhanced oil recovery, but also for other purposes. Thus, the engineering and technological details are relatively mature.

At the moment, 25 field geologic sequestration demonstration tests are being designed and scheduled for deployment in the United States over the coming 3 years. An additional 20 or so are scheduled for deployment soon in other countries. Most of these tests are using different technologies, including different engineering designs, different monitoring approaches, different risk assessment protocols, and different mitigation strategies. Most of these tests are relatively small in scale. Small injection rates compare to typical power plant emissions output. The uncertainties associated with evaluation and design of large-scale sequestration operations are fairly significant.

For large-scale geologic sequestration to be deployed and sustainable over the long term, a realistic field-based evaluation of uncertainties and how these uncertainties affect risk assessment and mitigation strategies must be carried out.

Additionally, the community also needs a meaningful assessment of CO_2-trapping mechanisms and the physical and chemical factors that may cause the mechanisms to lose efficacy under realistic field conditions.

Next year, the United States will begin deployment of several commercial-scale deployment demonstrations. These will sequester up to one million tons of CO_2 per year, the scale of a typical power plant.

The duration of these tests is 5 or more years. These tests will provide a good deal of the data required to maximize storage capacity and minimize uncertainty associated with commercial-scale sequestration, but not all of it.

Therefore, I suggest that incentives may be needed to provide the huge amount of data needed to ensure that commercial sequestration is robust and safe. Furthermore, I suggest that new incentives are needed to motivate industry to take on commercial sequestration as a routine part of business.

I list these suggestions here. First, I recommend incentives that will stimulate sequestration operations, with some assigned greater priority than others. Specifically, I suggest that the greatest priority incentives be assigned to deep saline formations underlying oil and gas fields to maximize relevant characterization data availability and the monitoring opportunities.

Next in the priority list would be deep saline formations not underlying oil and gas fields. Finally, the priority list and incentive ranking should include CO_2 injection in oil and gas reservoirs, with maximized sequestration and minimized CO_2 recycling.

Next, I recommend incentives that will assist with providing data necessary for liability risk and capacity assessments and other factors associated with sequestration. Specifically, oil and gas and other private entities hold a huge amount of data privately, and these data are essential to providing robust assessments of capacity and risk.

The DOE's regional partnerships, in collaboration with State Geological Surveys and the USGS are gathering a great deal of data and assembling them for public use in the form of NATCARB, a national carbon sequestration database.

If added, privately held data would likely more than double the size of that database, and as well would double our ability to assess capacity and risks of sequestration.

Next, I recommend that areas of the country that lack CO_2 pipeline infrastructure be provided incentives for building such pipelines. For commercial-scale sequestration to move forward, infrastructure will be necessary.

I recommend incentives for State, Federal, or privately sponsored indemnification. The States of Illinois and Texas assembled comprehensive indemnification plans for FutureGen, and these plans may serve as a template for future liability associated with commercial sequestration.

Lastly, the U.S. lacks a fully resolved regulatory framework. Any planned incentives for sequestration and enhanced oil recovery should factor in the evolving regulatory framework being developed by the EPA, the Interstate Oil and Gas Compact Commission, the regional partnerships, and individual States.

Thanks again for this opportunity to speak to you today. I look forward to any questions that you may have.

Senator BINGAMAN. Thank you very much for your good testimony.

[The prepared statement of Dr. McPherson appears in the appendix.]

Senator BINGAMAN. Mr. Bill Townsend is our final witness. He is the CEO of Blue Source out of Holladay, UT. Thank you for coming.

STATEMENT OF BILL TOWNSEND, CEO, BLUE SOURCE, HOLLADAY, UT

Mr. TOWNSEND. Mr. Chairman and members of the committee, thank you for the opportunity to appear before you today on the subject of carbon capture and storage as it relates to clean energy from coal and on the topic of potential incentives related to accelerating the development of carbon infrastructure.

My name is Bill Townsend. I am the chief executive officer and co-founder of the Blue Source companies. This topic is near and dear to my heart because, for the last 10 years, we have been developing companies specifically around carbon capture and storage long before it became the topic of the day.

Blue Source operates at the intersection of energy and climate change. Our companies and the management team they represent are in the unique position of having developed, designed, constructed, operated, and owned, in one form or another, all of the commercially-developed anthropogenic CO_2 pipeline systems for enhanced oil recovery in North America for the last 20 years.

In addition to developing anthropogenic CO_2 pipelines, Blue Source is the leading portfolio of greenhouse gas, or ghg, emission reductions. Our company has ghg offsets on public registries throughout North America, sourced from 11 different types of projects in 45 of the lower 48 States. With offset sourcing agreements through 2019, we are the largest ghg pool of this type in the world.

In the case of carbon capture and geologic sequestration, Blue Source has led in the development of carbon market protocols and sold, with one minor exception, 100 percent of the greenhouse gas emission reductions marketed from geologic sequestration.

The most recent example of our leadership in this area is as a steering committee member of the global voluntary carbon standard, which will be bringing quality assurance for buyers of offsets.

Today, Blue Source is in various stages of evaluating and developing 13 different vent stack-sourced CO_2 pipelines in North America. Over the past 10 years, the company and its affiliates have evaluated close to 100 such projects.

The primary reason only 5 percent of the projects that we have evaluated during the last 10 years has gone to construction phase is because, even with enhanced oil recovery efforts or oil-related revenues, the projects typically still yield a lower-than-accepted investment return.

Though higher crude oil prices in recent years have certainly helped that, a case in point is our La Veta CO_2 pipeline. For the last 5 years there were no sound economics to construct it, but with recent improvements in crude oil values and expected carbon offset sales, in 2006 we completed construction, and we expect to flow CO_2 on June 1 of this year. We have been venting CO_2.

As I describe in my written testimony, if Blue Source could have found additional financial incentives as small as 60 cents per MCF, or $10 a metric ton, we would have likely constructed another 15 projects with new carbon dioxide infrastructure of about 400 miles.

From our operating history and knowledge of CCS and building carbon infrastructure, we have a view of how to bridge the gap between the timing of current and expected CCS technology and the current and expected sources of vent stack CO_2 from power plants and other industries.

We believe the answer of managing the gap is a step process. First, over the next 5 years, financial incentives and regulatory influence should be used to accelerate CCS for CO_2 from non-power generation industries. This would primarily be ethanol, natural gas, refining, and fertilizer production.

Second, over the next 3 to 10 years, financial incentives and regulatory efforts would be directed towards CO_2 produced from the power generation sector for enhanced oil recovery.

Finally, we should immediately direct efforts to minimizing the potential regulatory and commercial barriers in developing CCS, including efforts to label CO_2 as a hazardous product and manage it as such.

It is clear that the long-term answer to single-point industrial CO_2 emissions, like power plant generation, is capture and storage in saline aquifers, not enhanced oil recovery.

That being said, there is a very strong, cost-effective interim answer for the next 10 years that employs the oil-based revenues and enhanced oil recovery to subsidize the infrastructure build-out and prepare the foundation for a carbon highway for the next generation of cost-effective carbon capture and power generation.

Today there exists 3,500 miles of CO_2 pipelines in North America that transport CO_2 to EOR sinks that were built on the back of oil revenues. Though originally built for underground sources of CO_2, today these pipelines carry both underground and vent stack CO_2 built from our projects.

We estimate that an additional 2,000 miles of anthropogenic CO_2 pipelines will be developed over the next 5 to 7 years in the U.S. by providing $10 per metric ton incentives, so long as crude oil prices stay reasonably at your current levels.

New power plant construction with IGCC or superamine-type retrofits, when combined with enhanced oil recovery projects, materially lowers the cost of capture. We estimate that, with incentives of $20 a metric ton, about 2,500 miles of CO_2 infrastructure would be added to the existing 3,500 miles over the next 10 years.

Our company and its affiliates have sold offsets from geologic sequestration since 1996 and we have heard about every reason why CCS-based offsets should or should not be included in a carbon offset trading program.

Accelerating the market acceptance that CCS is a valid ghg emission reduction is a direct benefit to further development of carbon infrastructure. Congress, citing geologic sequestration with or without enhanced oil recovery as an official part of its plan to manage the country's carbon footprint, would send a clear signal to voluntary and evolving State regulatory markets that value needs to be given to transactions of this type.

Clearly, the best long-term answers for CCS in the U.S. involve assessing saline aquifers, developing cost-effective separation technologies, and then bridging that gap with economic and financial structures.

That being said, we believe there are very meaningful steps that can be taken today and over the next 10 years that will bridge the gap significantly. In fact, the gap is bridged in much the same way that the 3,500 miles of existing CO_2 structure has been developed over the last years, relying on oil-related revenues and only accelerating that with regulatory incentives and forces.

This concludes my verbal testimony, Mr. Chairman and committee members, and I would be pleased to answer any questions.

[The prepared statement of Mr. Townsend appears in the appendix.]

Senator BINGAMAN. Well, thank you very much. Why don't we each take 5 minutes here and ask some questions, and then we may have a second round of questions after that.

One of the suggestions which a couple of you have made, or several of you, relates to putting in place what I would guess you would call a sequestration tax credit. Mr. Waddington, you make reference to that and talk about how, if there were a $20 per ton sequestration tax credit, that would incentivize a more aggressive effort to capture and store, or capture and sequester the coal.

Is it your view that that is adequate to actually cause companies that are producing power from coal to retrofit their operations or to go forward with new plants that would contain that technology?

Mr. WADDINGTON. Mr. Chairman, we have not done analysis to know whether the $20 per ton that we proposed would be the tipping point to your question. It certainly would make a difference and cause companies to look more seriously at CO_2 capture going forward. Whether it would cause them to retrofit existing plants, I rather doubt that, Mr. Chairman.

The reason we picked $20 per ton was to draw an analogy with the renewable portfolio tax credit that is on the books that Congress has provided. A $20 per ton CO_2 sequestration tax credit would be about the same level of subsidy, if you will, as the renewable credit. That is why we picked that dollar amount.

Senator BINGAMAN. Do any of the rest of you have a view as to whether this is the right kind of a mechanism, a tax credit of this type, for us to try to incentivize action in this area, or does this not get the job done, or miss the mark? Do any of you have a thought?

Mr. TOWNSEND. Mr. Chairman?

Senator BINGAMAN. Yes, Mr. Townsend?

Mr. TOWNSEND. There are a number of studies that have been done over the last 2 years, UNIPCC, I believe IEA, estimating the capture cost for IGCC and for retrofits on existing plants, and those numbers run from $25 to $45 per metric ton, depending upon the type of plant and the type of capture technology.

The reason we have landed on $20 as a basis for power generation is that, when you add that, plus $10 a ton that that CO_2 would receive from being sold into enhanced oil recoveries—because there is a value for the CO_2 in enhanced oil recovery as well, and that value can subsidize the carbon capture costs—our thought was that $20 for power plants, plus $20 for the actual value of CO_2-enhanced oil recovery, leaving the balance as the risk for the industry to take, was a pretty strong bridge to get somebody. We were two-thirds to 75 percent of the way there under most studies, and the balance can be taken on by industry.

Senator BINGAMAN. All right.

Mr. Diesch, let me ask you, you testified that some of the CO_2 emissions that you produce at your operation are, in fact, captured and sold, as I understand it.

Mr. DIESCH. That is correct.

Senator BINGAMAN. Well, what percent of the CO_2 emissions that you are responsible for there are captured and sold, and what is the current price of a ton of CO_2?

Mr. DIESCH. We have the opportunity to capture all of the CO_2 that comes off the process side. Now, there is CO_2 that comes off of boilers, because we use a lot of natural gas to actually heat the process. We do not have the capability at this time to be able to capture that, but we have the ability to capture 100 percent that comes off the ammonia process.

We sell our CO_2. It is food grade, so we clean it up to be able to sell to, like, Pepsi-Cola and Coca-Cola and such, and that typically runs between $30 and $40 a ton, the value of it.

Senator BINGAMAN. That is after it is cleaned up.

Mr. DIESCH. After it is cleaned up and liquified.

Senator BINGAMAN. All right.

What would it take, by way of tax incentive or otherwise, to persuade your company to capture all the CO_2?

Mr. DIESCH. Well, in an ammonia plant, we are moving in that direction currently, because with a retrofit utilizing coal gasification, we have the capability of capturing much more.

The technology allows us to capture much more of the CO_2 off the process, because it is inherent in gasification processes that you can do that. It is a concentrated stream. So, we are already moving in that direction and will have the capability.

Senator BINGAMAN. So you are not arguing that additional tax incentives by the Federal Government are needed at least to incentivize your company to do what should be done here?

Mr. DIESCH. Well, for us to move forward, of course, the economics have to be there. With the products we produce, there is significant value on ammonia and the nitrogen products, plus the fuels products, that allows us to move forward. But not all projects may have the economics.

Senator BINGAMAN. Right.

Mr. DIESCH. So there has to be an incentive to kick-start the industry, as I said earlier. You need to kick-start the industry.

Now, we have been moving forward with our project. We have gotten some help from the State of Illinois that has assisted us in our initial engineering studies, but for the most part, this plant is going to stand on its own. Now, future plants may not be that way, depending on economics and the location, construction, and design of the facility.

Senator BINGAMAN. Very good.

Senator Thomas?

Senator THOMAS. Thank you.

First of all, let me tell you how much I appreciate you all being here and talking specifically about how we can do something in this area, because I think it is so important, with your solutions.

I might mention to Mr. Diesch, in our energy bill that we introduced last year, we did have long-term contracting authority, and we will try to do that again.

Mr. Waddington, are you aware of any Wyoming IGCC projects that applied for tax credits under the energy bill, and were any awarded?

Mr. WADDINGTON. Mr. Chairman and Senator Thomas, I am aware that there was at least one application. I have been told that PacifiCorp applied to be certified as eligible. My guess is, there were other projects in Wyoming that applied, but I do not know that for sure.

Senator THOMAS. What was the primary difficulty or obstacle, do you know?

Mr. WADDINGTON. Mr. Chairman and Senator Thomas, we actually do not know for sure, because the Department of Energy has not disclosed its evaluations. But we suspect, and it is generally thought, that the 99-percent SO_2 removal standard that was in the Energy Policy Act was a pretty tough hurdle for using western subbituminous coal. That has been fixed now, with your leadership and the Chair's leadership, so we hope in the second round that Wyoming projects will be given a better shot.

Senator THOMAS. I see. I guess my point is, we are talking a lot about what we need to do, and the fact is, we have some things that could be done that are not being done. So, we need to move forward with that.

Dr. French, you mentioned the possibility of changing existing power plants so they could work with this extraction of CO_2. Is that practical?

Dr. FRENCH. There were two things I mentioned. The first is increasing efficiency, both for existing plants and for new plants. The technology is available today to increase efficiency. So then you are making less carbon to start with, and that is what the industry believes is the number-one place to start.

The problem is, a higher-efficiency plant costs more and electricity is a commodity, so we need to incentivize the people who have existing plants and new plants to spend more to upgrade to increase efficiency.

Senator THOMAS. Can you upgrade an existing plant for efficiency?

Dr. FRENCH. You can. You cannot get the very, very high efficiency that you can from new boiler technology or highly efficient IGCC, but there are a lot of things you can do at both the boiler stage and the turbine stage to increase efficiency. Every 1 percent makes a big difference in the amount of carbon you have to treat later on. There is no incentive right now for that, and I really believe those technologies are available.

Senator THOMAS. FT fuels. Are you in the marketplace now? Can you compete in the marketplace for FT?

Mr. DIESCH. No, we are not in the marketplace. The first commercial-scale production facility will be East Dubuque, and it will be 2010 before we will actually be in the marketplace.

Senator THOMAS. And you will be competitive then?

Mr. DIESCH. Oh, absolutely. Absolutely. Yes.

Senator THOMAS. Dr. McPherson, you mentioned capturing and using CO_2 to recover. How are you going to get it to the oilfields?

Dr. MCPHERSON. That is probably one of the greatest obstacles. In the States of New Mexico, Colorado, and western Texas, and also in Wyoming to a great extent, there are existing CO_2 pipelines for transporting CO_2 to different fields, from source to sink, so to speak.

For those areas of the country that do not have such a nice infrastructure for transporting CO_2, it would be terrific to have some incentives available to motivate that new infrastructure.

Senator THOMAS. Well, obviously Mr. Townsend has said how we can do that, but there is a little problem in the difference between where coal production and the use for recovery for oil are close enough that it would be practical to do that. I guess that is the fact.

Oil recovery. Can we make that economically possible to get that through your pipelines to where the oil is?

Mr. TOWNSEND. Senator, yes, I think we can. I think oil prices being above about $40, $45 offers a really strong base. CO_2 prices in west Texas today are about 2 to 2.5 percent of the Oil Price Index, so that runs 80 cents to $1.50, or $10 to $15 a metric ton.

Senator THOMAS. Where is the coal production?

Mr. TOWNSEND. That is the sink. And so to connect the sink and the source, the power plant is put somewhere between the sources of coal in the Rockies or in the Midwest. The sinks—if you look at an ARI study that was recently done identifying the sinks in the U.S., both oil sinks and saline sinks, they are substantial. In fact, one thing the U.S. has is not a shortage of sinks.

Senator THOMAS. So, you mean you would just sequester.

Mr. TOWNSEND. Yes, sir.

Senator THOMAS. All right. Not for recovery of oil.

Mr. TOWNSEND. Well, our suggestion is to use oil revenues as the basis for starting the infrastructure build-out, pay for part of it with that so that the saline aquifers can then be done cheaper.

Senator THOMAS. Okay. Thank you.

Senator BINGAMAN. Senator Kerry?

OPENING STATEMENT OF HON. JOHN KERRY, A U.S. SENATOR FROM MASSACHUSETTS

Senator KERRY. Thank you very much, Senator Bingaman. Thank you for this hearing.

This morning in the Commerce Committee we had a similar hearing on the issue of clean coal technology. We had two witnesses, Joseph Chaisson, the director of Research and Technology for the Clean Air Task Force, and Dr. Gregory McRae, who is a chemical engineering professor at MIT and one of the authors of the Coal Report study. Then we had a number of other folks out of the industry, from Siemens and elsewhere, American Electric Power.

It was interesting because, first of all, they all concluded that we have to do this urgently. Some of the years you were talking about, 5 years to get here, 10 years for that, the indicators are, we do not have that kind of time to wait until we have an ability to burn clean, if you accept the science.

This is an issue where, as we said this morning, you cannot be half pregnant on this issue. If you accept the science and you believe what the scientists are telling us, then you have to accept sort of the framework that they are offering us within which we prevent catastrophe. Do you accept that, all of you?

Mr. WADDINGTON. Yes.

Dr. FRENCH. Yes.

Mr. DIESCH. Yes.

Dr. MCPHERSON. Yes.

Mr. TOWNSEND. Yes.

Senator KERRY. All right.

So as a starting point, we have to get more serious than we have been, which means we need some pretty big incentives, correct? Give me an order of magnitude. What are we talking about that we need to think about on this committee? They said we need at least a billion dollars a year that has to go straight into clean coal to augment just the capture and sequestration issue. Where do you come down on that figure?

Mr. WADDINGTON. Mr. Chairman, Senator Kerry, I would be happy to provide my opinion on that. I think you are absolutely right. If we are going to take climate change seriously, we have to recognize that the solutions are going to be expensive, they are going to be large-scale.

It is going to take time. There is a significant role for the Federal Government to incentivize, match, buy down the risk, and move ahead, both with coal conversion technologies that allow for the capture of CO_2 and large-scale geologic sequestration at multiple sites.

Senator KERRY. You used the word "if" we are going to take it. Do you have any doubts whether we ought to?

Mr. WADDINGTON. Well, the current Department of Energy coal program, which has been in a diminishing decline for a number of years, if you set aside FutureGen, the fiscal year budget is about $200 million. Can we increase that to a billion dollars a year?

Senator KERRY. No, no, no. What I am saying is, I agree, it is minimalist and it is anemic, and we are not getting the job done. What I am saying is, you said if we are going to take the climate change thing seriously. I am just saying to you, do you believe we have to?

Mr. WADDINGTON. I personally believe we have to, Senator Kerry.

Senator KERRY. All right. So do I, and I think the consensus of the scientists is that we do, but I wanted to just get that as a baseline.

Now, in the 1930s when electricity first began to be distributed in America, Franklin Roosevelt made the decision that every home in America ought to get it as fast as possible because it was an urgent part of our economic development and future.

We did the TVA. Government became involved. I think we invested about $5 billion back then in infrastructure to make it happen. Is there any reason that similarly, now, given the 10-year window that our chief climatologist, Jim Hansen, has given us and the increased feedback on this——

I mean, every scientist I have talked to, and I have talked to a bunch of them lately—Bob Correll, Ed Miles, University of Washington, John Holdren, Harvard, and so forth—they all say the evidence, the feedback, all of their predictions are coming back now at a faster rate and in a greater quantity than they anticipated. So they have refined their own judgment of what we have to do.

We cannot, now, have an increase of three degrees Centigrade, we have to hold it to two degrees Centigrade. We cannot, now, have an increase of 550 parts per million in the greenhouses gases, we have to hold it to 450. Now, if you accept that, do you not have to put in place an incentive that is absolutely clearly going to get you the marketplace behavior that you need? That is the first part of the question.

The second part, does that incentive need to be broad-based so that you take the 15 or 20 clean coal technologies out there and you let any of them emerge within that, or do you take the 4 or 5 most promising? Go ahead.

Dr. MCPHERSON. Thank you, Senator Kerry. There is some "low-hanging" fruit out there. There are two issues that I think need to be addressed: one is capture, the other is storage, and they are completely separate. As Mr. Townsend mentioned, the cost of separation and capture ranges anywhere from $25 to probably even $50 or $60 per ton. The cost of storage, depending on the depth and the type of formation used, ranges anywhere from 50 cents to $10 per ton.

So there needs to be, as I mentioned earlier, infrastructure to provide the storage, but firstly, some incentives to motivate the capture. The capture is by far the most expensive portion, but also the country does not have the necessary extensive infrastructure required for distributing CO_2 to the sinks, to the different oil and gas reservoirs for enhanced oil recovery or the deep saline reservoirs.

One argument that I would like to make is, if we can focus on oil and gas fields and deep saline storage underneath oil and gas fields where there is existing infrastructure, there are extensive data sets available for characterizing risk and capacity and those kinds of things, and you can incentivize and have a priority ranking of different storage sites.

I suspect, as you have already alluded to, there are different rankings and priorities for capture types. So if incentives are provided, if they are ranked and prioritized and given different weights, that might be a way forward.

Senator KERRY. We know we can capture. We have the technology to capture. We simply have never done it to scale, correct?

Dr. FRENCH. The capture technologies are very expensive.

Senator KERRY. But we have never done it to scale.

Dr. FRENCH. And we have never done it to scale.

Senator KERRY. But we know we at least can capture.

Dr. FRENCH. Yes.

Senator KERRY. If the economics do not work and you cannot do this, can you build a coal-fired plant? Should we? If you cannot capture and you cannot sequester, should we build a coal-fired plant?

Dr. FRENCH. I think we can capture and we can sequester.

Senator KERRY. If we cannot, should you build a coal-fired plant without it? If you do not, though. I am saying, if you do not spend the money, if you do not get the economics here. We know we can if we spend the money, but we have not indicated that we are willing to spend the money yet to do this. I am just asking the question. If you do not do it, it is an important threshold from which we need to operate.

Senator BINGAMAN. Anyone would like to respond, please do so quickly. Then we will go the next question. No one wants to respond?

[No response.]

Senator BINGAMAN. Senator Bunning?

Senator BUNNING. Let me make a statement, first of all, then ask some questions.

Would you consider this statement true or false, all members of this panel: The United States can get to zero emissions, and, if we get to zero emissions in all the things that Senator Kerry is talking about and we do not do something about the fact that China and India do not have some kind of an agreement to do likewise, we will have no effect on climate change?

Mr. WADDINGTON. Mr. Chairman, Senator Bunning, I am not a climate change expert.

Senator BUNNING. All right. Then do not answer the question. Next?

Dr. FRENCH. I am not a climate change expert either, but I would like to say the National Coal Council is completing a report that talks about the global impact of CO_2. The drafts are almost finished. It will be out very shortly. There is an excellent summary of exactly that question, but it would not be fair for me to try to paraphrase it.

Senator BUNNING. All right.

Anyone?

Mr. DIESCH. I am not an expert. I am a fertilizer guy. So, I will pass.

Dr. MCPHERSON. I would suggest that India and China, if we take the lead, might follow along. I am not sure if they will.

Senator BUNNING. In other words, we should go and take the lead and get to zero emissions if possible without any agreement on China and India doing likewise? Would that have an effect on our economy?

Dr. MCPHERSON. Carbon is evolving into its own industry and I think—

Senator BUNNING. I mean, but would it have an effect on our economy?

Dr. MCPHERSON. It could be positive.

Senator BUNNING. All right.

Sir?

Mr. TOWNSEND. I am definitely not a climate change expert, but I do think we need to take a leadership role in this area.

Senator BUNNING. Without anybody else signing on?

Mr. TOWNSEND. I think other people will sign on. They have in the past.

Senator BUNNING. You have not been dealing with China very long then.

Mr. TOWNSEND. No, I have not.

Senator BUNNING. All right.

Dr. FRENCH. Senator Bunning, Thomas Friedman, who is an op-ed contributor for the *New York Times*—I think you are familiar with him—has some very interesting answers to that question also.

He points out that we are a country that has gone through its growth cycle. These are countries that have not gone through the same growth cycle, they are at the earlier stage. We went through our growth cycle with power production and CO_2 emissions, and now we are coming to clean them up.

He points to the fact that these countries, as they go through their growth cycle, there is a very good chance that they will come and catch up with us, but that we are the leader and have the ability to provide that leadership by coming first. Do we go to zero? I do not think so. But do we take a leadership role? I think we can.

Senator BUNNING. I hope you all visit China during the 2008 Olympics so you can spend a week in Beijing, like some of us on the Finance Committee did about a year ago, and cry as you sit in your hotel and as you walk down the street. The emissions are such that you cannot even see. Believe me, I was a professional athlete and played in Los Angeles as a professional athlete in 1969. If I got up before noon, I could not see Los Angeles. I have news for you. If you get up before noon now, we have done a great job in cleaning up a lot of the emissions in Los Angeles so you can see before noon, and the haze lifts.

Mr. Diesch, I want to ask you one specific question. You highlighted two tax incentives as top priorities, a coal-to-liquid tax credit like the gasification tax credit in section 48B, and a carbon capture credit.

I have introduced legislation, S. 155, the Coal-to-Liquids Fuel Promotion Act, which Senator Thomas has co-sponsored, that would create a new section 48C tax credit for coal to liquids and provide a 50-percent tax credit for carbon capture and sequestration equipment. Are you aware of this legislation, and do you think it provides the right incentive for the technology?

Mr. DIESCH. I am somewhat aware of the initial legislation. I do not know all the details. But, absolutely, I think that is extremely important to kick off the industry, because carbon capture and cleanup is an absolute requirement in the process of producing Fischer Tropsch, because you have to have a very clean gas stream. So the technology that we were using, the best technology today is called Rectisol, it cleans the gas streams up extremely well.

In order to produce Fischer Tropsch fuels or liquids, you have to utilize those technologies. So it will incentivize the further-on development of the industry moving forward. I definitely believe that is going to help.

Senator BUNNING. My time has expired, Mr. Chairman.

Senator BINGAMAN. Thank you very much.

Senator Hatch?

Senator HATCH. Well, thank you, Mr. Chairman. As you know, we have two witnesses at today's hearing with ties to my home State of Utah. We have Dr. Brian J. McPherson, director of the Southwest Regional Partnership on Carbon Sequestration, and he does work for both New Mexico Tech and for the Energy and Geoscience Institute at the University of Utah. I will not ask him in public which of the two jobs he prefers the most.

We also have Bill Townsend with Blue Source Energy from Holladay, UT. As you know, Mr. Chairman, Blue Source Energy is one of the Nation's leaders in CO_2 pipeline systems, one of the most critical technologies for capturing and sequestering CO_2.

Now, Mr. Chairman, I thank you for inviting these two experts to testify today. And I welcome all of you, as well as my two folks who have ties to Utah, in helping us to understand one of our Nation's most vexing problems, and that is capturing and sequestering CO_2. This is an important hearing.

Let me turn to you, Mr. Townsend, first. It appears that the pipelines that your company has been involved with are geared towards enhanced energy production. Have any CO_2 pipelines been built in this country strictly for the purpose of geologic sequestration of CO_2?

Mr. TOWNSEND. No, sir. There may have been two small pilot projects done, but not for commercial purposes.

Senator HATCH. All right.

You mentioned the need for more pipeline infrastructure to transport CO_2. Today it appears that it comes down to economics because of the number of pipelines that have been built to transport CO_2 for the purpose of enhanced oil and gas production without any government assistance that I am aware of.

Other than subsidies, what are the potential market drivers that would make CO_2 pipelines economically feasible when their purpose is not to enhance oil and gas recovery, but simply to put CO_2 into the ground?

Mr. TOWNSEND. I am not aware of any additional economic drivers to putting CO_2 in a saline aquifer besides the climate change impact, Senator Hatch.

Senator HATCH. All right.

Now, Dr. McPherson, you talked about commercial-scale sequestration demonstration projects that will be coming online in the near future and the importance of the data that will be collected during these projects.

Currently, we have no regulatory scheme for the sequestration of CO_2. What types of information does the government need to have before we will be in a good position to set up a meaningful regulatory scheme for sequestration?

Dr. MCPHERSON. Well, the current regulatory framework for oil and gas serves at least as a good model. I mean, it is effective for oil and gas. Oil and gas obviously are a commodity. CO_2, at least in the western U.S.—well, throughout the U.S. but more so in the western U.S.—is a commodity as well, a very strong commodity, and regulating it as such might be helpful by mimicking what already works for oil and gas.

Focusing on oil and gas fields and deep saline reservoirs below oil and gas fields might be a way to start because, in those areas, the regulatory structures and detailed issues, unique issues specific to those areas, have already been worked out. So, there are many reasons why focusing on those areas might be helpful. Also, the infrastructure for CO_2, the rights of way for pipelines, exists in those areas.

Senator HATCH. Now, you talked about the need for government incentives to promote the infrastructure needed for large-scale CO_2 sequestration in our country. Even with government assistance, though, will there not have to be some natural market incentives to drive this activity? Could you talk about what incentives would be in the market for this type of investment?

Dr. MCPHERSON. Yes. As Mr. Townsend mentioned earlier, starting with enhanced oil recovery, that would build the motivation, build the impetus, if you will, for driving the initial early stages of commercial-scale sequestration, if we tie enhanced oil recovery with sequestration per se, use that tax base, use that profit base to develop infrastructure for sequestration rather than just oil recovery.

Then also at those sites for oil and gas recovery, maximize subsequent storage of CO_2. Give incentives for not just recycling CO_2, which is typically done at an oil field—it is injected into a deep oil reservoir underneath a confining layer that is used to break up the viscosity of the oil and reproduce it; the CO_2 is reproduced and recycled. If that CO_2 is then re-injected for storage, then that is, again, another follow-on with what is already happening with oil and gas and that experience.

Senator HATCH. Well, thank you.

Dr. French, you referenced the large differences among the various coal resources in this country, and clearly some coal is cleaner than others in terms of criteria pollutants.

In terms of CO_2 per Btu, though, does some of our coal produce more greenhouse gases than other types of coal? If so, where do you find our Nation's cleanest coal in terms of CO_2?

Dr. FRENCH. Senator Hatch, that is an excellent question. From a combustion point of view, carbon is carbon. It does not matter if you make the energy from gasification or an old plant or new plant, carbon is carbon.

If you take the carbon out of coal, we call that sand, and you cannot burn it and make electricity. So carbon is carbon. So the amount of carbon that is put out from a low-rank coal or a high-rank coal is still the same.

The question is, for gasification, the CO_2 that comes out is concentrated so you do not have to take the nitrogen out of the system to start with, so that makes capture, perhaps, more amenable in gasification.

But there are some efficiency differences also, so there is no one answer. The most important thing that we are going to have to deal with in carbon capture and storage is the recognition that there will be a different set of technologies required for each application, and we need multiple technologies in order to bring the cost down and move forward.

Senator HATCH. I am sorry I ignored you, Mr. Diesch, and you, Mr. Waddington.

Are you related to Thorpe Waddington?

Mr. WADDINGTON. Senator Hatch, no, I am not.

Senator HATCH. All right. I just wanted to know if you were. He is a Utahn, a great natural resources guy who died a few years ago.

Thank you, Mr. Chairman.

Senator BINGAMAN. Thank you.

Let me ask a couple of other questions here, and I am sure some of the other members will have additional questions as well.

Let me ask you, Dr. McPherson, is there currently a standard for the purity of CO_2 that is transported in pipelines?

Dr. MCPHERSON. Mr. Chairman, I hope I do not misquote the standard. I believe it is 97 percent, but I could very well be wrong. I know that the purity of CO_2 in the Cortez and Sheep Mountain pipelines, those going from Southern Colorado through New Mexico into Texas, is approximately 97 percent.

Senator BINGAMAN. And who establishes the standard?

Dr. MCPHERSON. That is borne by UIC (Underground Injection Control) regulations, but also oil and gas, local State regulations for injection and production of oil.

Senator BINGAMAN. So you think it is a State-level standard instead of a Federal standard?

Dr. MCPHERSON. I believe it is governed by the States.

Senator BINGAMAN. Should we have a Federal standard in place as to the purity required for CO_2 to be transported in pipelines or is that something that—I mean, if this is going to become a significant activity, it would seem appropriate to have something like that. Maybe not. I do not know. Maybe Mr. Townsend has a thought on that. Either one of you?

Dr. MCPHERSON. My opinion is, 90 percent purity, minimum, would be appropriate. Depending on the type of capture used, there are going to be different expenses for getting that additional 5 to 7 percent of the 97.

Senator BINGAMAN. Did you have any thoughts on that, Mr. Townsend?

Mr. TOWNSEND. Mr. Chairman, there is an industry specification for CO_2. It is based on the use of CO_2 to capture oil, and that specification is, in most contracts, 95 percent pure CO_2, certain percentages of nitrogen and oxygen as well, and H_2S.

The reason it is 95 percent, although there are some injections done at 94 percent, is that when the CO_2 is injected into the ground and it mixes with oil, it is miscible. It mixes with it cleanly and then it sweeps the oil off the face of the reserve.

As the percentage of CO_2 decreases, the amount of pressure required to have the CO_2 and the oil mix and become miscible grows and grows and grows and you need more and more horsepower to cause CO_2 that is miscible at 90 percent than at 92, 93, 94, 95.

So the underground sources of CO_2 that Dr. McPherson was just mentioning are very high purity forms. Out of Colorado, the Four Corners area, and Eastern New Mexico, they run 97 to 98 percent pure CO_2, but actual work in the field suggests that 95 percent, which is what most contracts are written at, is the minimum specification for CO_2.

Senator BINGAMAN. I am trying to get in my head, Dr. McPherson, you talked about how there is a big difference between capturing and sequestering, and the cost of capturing the carbon is substantially greater per ton than the cost of sequestering it.

If we were to try to put some kind of tax credit in place, how would you structure that? Would it make sense to have a tax credit just for the capture or should there be a separate tax credit for capture and a different one for sequestering it?

I mean, I would think that if the practice of capturing becomes widespread, and storing or sequestering carbon from coal plants becomes widespread, there are going to be people in the business of just doing one rather than the other.

I mean, maybe the plant would do the capturing and then someone would come along and sign a contract that they would take what was captured, transport it, sequester it, get paid.

Do you have a thought as to how you would structure the tax credit?

Dr. MCPHERSON. Yes, Mr. Chairman. I would recommend that your idea of separating them, one for separation, one for storage, actual injection and sequestration, would be appropriate, simply because ethanol plants and some other plants, the technologies for separating CO_2—with IGCC, it is very different.

So depending on the type of plant, whether it is a chemical plant or a coal-fired power plant, et cetera, depending on the type of plant, there will be different needs and different technological requirements for separating and capturing the CO_2, and therefore different cost structures. Whereas, sequestration is, by itself, by and large, a known technology, a known engineering approach through the existing oil and gas—

Senator BINGAMAN. Of course, we really do not have any policy reason to want them to just capture it. I mean, the whole idea is, we want it not in the atmosphere. So they have to do both in order to accomplish the objective we are trying to accomplish through the tax code here.

My time is up. Let me see if Senator Thomas has other questions.

Senator THOMAS. Just very quickly. Dr. French, you commented that we need to provide incentives based on achievement of goals rather than specific technologies. How do you suggest we best do this without opening the door to all kinds of activities that may or may not be productive?

Dr. FRENCH. Senator Thomas, that is a good question. I am not a tax policy expert, but I do understand technologies, I understand energy, so what I can speak to is what I have seen in the past.

That is, if we carefully define what our goal is and set clear baselines and clear guidelines, metrics to measure those goals, we will end up with strong tax incentives that do actually accomplish things.

That comes from understanding the industry and the quirks of the industry. It is one thing to say we want to improve efficiency. The devil is in the details of, how do you define a baseline efficiency such that the credit actually does what it is meant to do?

Senator THOMAS. All right.

Dr. FRENCH. Does that answer your question?

Senator THOMAS. The concern, often, when we get into, sort of, the incentives, is we end up more in research than we do in productivity.

Dr. FRENCH. I agree.

Senator THOMAS. I think we are at a point now where we know pretty much how to do some of these things and we ought to be incentivizing those things we know how to do.

Dr. FRENCH. And my understanding of that, what I see is, when you write an incentive that is a production incentive, that the tax credit comes in when you actually accomplish it. Then you stay away from subsidizing research and development.

Senator THOMAS. Good.

Dr. FRENCH. And I think that has been shown to be very effective.

Senator THOMAS. Mr. Waddington, we have talked a little bit about it, but the fact is, coal is one place basically and the markets are other places, so we need to get transmission in order to be able to do these things.

How do you suggest that we get transmission capacity going?

Mr. WADDINGTON. Senator Thomas, at least in Wyoming, we are doing a lot to try to get transmission wires in the air. We would like to see mine mouth coal plant development in Wyoming. It is lower cost because you are proximate to the coal.

In the future as we move to sequestration, those plants will also be more proximate to the best sequestration opportunities. So, we think that is the way to go, but transmission will be required.

There are several transmission projects that we are involved in, looking at proximate markets such as Denver, Salt Lake, Phoenix, and ultimately California. The infrastructure authority was created to be a proactive catalyst for getting transmission built, and I think will be successful.

Senator THOMAS. Yes. Well, I think one of the examples we need to keep in mind as we talk about this, in this instance the largest supply of coal currently is in Wyoming. The largest market for electricity is in California.

So, it is much safer for the environment to be able to get it there on a transmission line than it is on a railroad car, and so we need to make sure that we get these incentives happening where we can get all these factors together.

I am a little disappointed, for instance, that we have been working at it in Wyoming, getting some incentives for the coal production where the coal is, and we have yet to be successful. So, thank you.

Senator BINGAMAN. Senator Kerry?

Senator KERRY. Well, picking up on what Senator Thomas said, I agree with Senator Thomas that it is important to get the incentives for the full package: for the transmission as well as for the production as well as for the capture or the sequestration.

But in addition, I agree with him that we do not want to encourage activity that somehow is not productive. That is always tricky if you are trying to excite creativity and innovation.

That is what I asked earlier about this question of, there are 15 or 20 different technologies out there, but there are only about 5, I think, that are "in use," though not to scale, but which people think might be brought to scale, effectively.

So, where do we put our incentive here? Do we go for the full 20 and let us see what happens and let the marketplace decide? Because if we get narrower, then we are doing the very thing that most people say do not ever do, which is to start picking winners and losers. Is there a way to frame this so we are not picking them, but still not wasting money? Does anybody want to respond?

Dr. MCPHERSON. If the standards are benchmarks based on production rather than a specific technology, then the market would drive the winners versus losers.

Senator KERRY. So the standard ought to be X amount of CO_2 captured.

Dr. MCPHERSON. Some efficiency. Yes.

Senator KERRY. Efficiency standard, period, within that. But that is going for production. So you are not for putting any of the money—what about the R&D component of this?

Dr. MCPHERSON. Certainly there are, as you already suggested, some technologies that are winners, clearly, some that are not. As far as I know, there are significant funding mechanisms in place right now in R&D to move forward, as you and Senator Thomas suggested, to action.

Senator KERRY. There are. But at the same time, I have heard from a lot of folks, including the panel this morning, that there is a significant need for increased R&D, particularly on the sequestration side, but also even on the capture.

Mr. Diesch?

Mr. DIESCH. Senator Kerry, I assume you are talking about different gasification technologies and clean-up technologies, I assume, for cleaning out the gas and removing the CO_2. I think the marketplaces will dictate that because it is depending on its use. We are a Fischer Tropsch fuels production, so we have to have very clean gas streams because of our catalysts and contamination issues.

So the gasification technology we use is dictated by two things. Number one, what is the component of the gas streams that are coming off the gasifier? Number two, what type of coal are you going to use? There are different gasification technologies that work better on different types of coals.

If we are going to be using Illinois #6 coal, we are going to use ConocoPhillips gasification technology because we get the most heat recovery, we get the most efficiency out of the coal, and it gets us the components in the gas stream that allow us to produce the products we need to produce.

Senator KERRY. Let me ask you about that for a moment, because you are involved in both coal to liquids and gas to liquids, correct?

Mr. DIESCH. No. The plant in East Dubuque produces diesel fuel and fertilizer, nitrogen fertilizer.

Senator KERRY. So you are not doing any coal to liquids?

Mr. DIESCH. Yes. The two major liquid components you are going to get from Fischer Tropsch is, you can either produce diesel fuel or jet fuel, the easiest products you can produce, and most cost-effective.

Senator KERRY. Fair enough.

Now, why should we give an incentive to that, given that a lot of people are telling us that the well-to-wheels rate for conventional petroleum-derived fuel is about 27 pounds of CO_2 per gallon of fuel, whereas the coal to liquid is about 50? And even if you capture it, if it is fully captured, you still are at a higher percentage than you are for the other forms by about 10 percent, 8 to 10 percent.

Mr. DIESCH. That is incorrect. There have been a number of studies. Toyota did a study in 2004. The U.S. Army has done some studies on efficiencies and CO_2 emissions. The quickest way to reduce emissions on vehicles is to switch from gasoline to standard diesel fuel. That will give you about a 21-percent reduction of CO_2 emissions.

Now, if you take Fischer Tropsch and you have gone through optimizing the CO_2 removal, you will reduce that even further compared to gasoline, up to a 30-percent reduction, but you will have to optimize the CO_2 removal, again, from wells to wheels.

Senator KERRY. And what is the emissions and energy use, comparatively, in the process of doing that?

Mr. DIESCH. It is comparable. It is comparable.

Senator KERRY. It is?

Mr. DIESCH. Yes.

Senator KERRY. Well, I would like to see that study, Mr. Chairman, if we could get that and make it a part of the record. I would like to get a comparison with some others I have had and examine that a little further, because I guess there is a conflict in the data there.

[The study appears in the appendix on page 64.]

Dr. FRENCH. Senator Kerry?

Senator KERRY. Yes.

Dr. FRENCH. There is data in the National Coal Council report on this also, and it backs up what Mr. Diesch was saying.

Senator KERRY. I would not be surprised if it did. I do not mean to be disrespectful, but I just want to check it, that is all. I would like to get at it. I would like to understand it, that is all. I just want to know. Because if you read one thing and it says one thing, you want to understand how it does get refuted, that is all. I would like to understand it, so we will try to get at it.

I think it is important to make sure, if we are providing incentives and spending the money, that we are not negating somehow or making more complicated the whole picture of what we are going after. But whatever is legitimate, is legitimate and should be on its face.

If I could just say to Senator Bunning on the China thing just for a moment, I have been involved with their delegations, and others, for 17 years now. We met with them early on during the early negotiations on the voluntary exchange.

We also met again during the Kyoto negotiations. I managed the Kyoto piece on the floor when we did Byrd-Hagel. There was a universal acceptance here that we needed to get the world involved; less-developed countries, other countries have to be involved.

Most recently, we had a meeting here in Washington with a very large Chinese delegation, the Global Legislators for a Balanced Environment. Japanese, Europeans, and a lot of people were there.

There is a strong consensus between Europeans and a lot of other folks who are moving down this road that we need to take some action. We may not get to zero, but if we take action, the Chinese are poised to also take action, as are the Indians.

In fact, they are planning to shut down their plants. There was a big article in the *New York Times* a few weeks ago about their concern for the professional athletes during the Olympics.

They are well-aware of the problem, and they are planning to take steps, unilaterally, obviously, to try to deal with that problem, as Atlanta did, I might add. Atlanta, during the Olympics, did an entire transportation plan and reduced the emissions so the athletes would be able to perform at a higher level.

So, there is precedent for it. I think it is the judgment of most people that, if the United States is 25 percent of the world's emissions, we are going to have to start down that road and take the lead. We have enough market power and enough leverage, I think, that in the end the Chinese are going to be interested in buying our technology and sharing in this effort.

Obviously, if they do not do it, we are all hurt. But if we do not do it either, nobody is going to do it. Up until now, they have viewed our reluctance as kind of a western conspiracy against their ability to develop, and that is a view of a lot of less-developed countries. And you may laugh about it, but the fact is—

Senator BUNNING. I am not laughing. I am smiling because I went there and had to deal with it.

Senator KERRY. You have to deal with people's perceptions. I think if we start down the road, we have enough market lift, together with Europe, that we could make it pretty uncomfortable for them if they do not go down the road with us.

Senator BINGAMAN. Senator Bunning?

Senator BUNNING. Well, I know that they are going to shut down their power plants for the Olympic Games and use a transportation setup, at least that I have heard of, that will be similar to Atlanta. You will not see one car on the road in Beijing during the Olympic Games. You will see transportation by buses and by other vehicles.

But still in all, if you weigh the 94 coal-fired generating plants that China is opening this year—this year—comparatively speaking to what we are doing as far as opening new plants this year, we have a much better handle on our emissions than they do.

Going down the road, if we are going to approach climate change and climate control, we are going to have to do it. If we take the lead and hope somebody follows, that is not the answer. We have to make sure that they follow us.

Senator KERRY. Of course. But you have to have clean hands in that discussion.

Senator BUNNING. Well, I mean, what is clean hands?

Senator KERRY. It is making a legitimate, bona fide effort to prove that you are going to do these things.

Senator BUNNING. Thank you.

Dr. French, you said that technology development will be the key to clean coal technology. I have watched as many of our tax incentives we wrote into the Energy Policy Act in 2005 have led to dramatic pollution reductions in sulfur, nitrogen, and particulate matters, emissions. Do you agree that expanded tax incentives for clean coal can address the need to improve power plant efficiencies and decrease carbon emissions?

Dr. FRENCH. Senator Bunning, yes, I do believe that. I think that the efficiency improvements are closer than full-scale commercial carbon capture and storage for coal.

But I think we need to work carefully with the regulations, with the technology development support that Senator Kerry was talking about to move forward with that as quickly as we can. I think the tax incentives would work ideally for efficiency improvements in both existing plants and new plants, because the higher efficiency will cost more. We need to level the playing field.

Senator BUNNING. All right.

Would you, Mr. Diesch, mind repeating what you said about liquids that are obtained from coal through the Fischer Tropsch process and the possibility of cleaner fuel being a result of that process, and the ability to capture carbon? Now, South Africa is doing this on a much larger scale than we ever hoped for.

Mr. DIESCH. That is correct.

Senator BUNNING. So we do not have to reinvent the wheel. Can you enlighten us on that?

Mr. DIESCH. I think, Senator Bunning, you are asking me to kind of give you a quick description of how the process works?

Senator BUNNING. Well, I know how the process works. I am talking about, as you produce the liquid from the coal, you can capture the carbon.

Mr. DIESCH. Yes.

Senator BUNNING. And after you capture it, you can do other things with it. You can sell it. You can sequester it. There are many uses for carbon at 95 percent, as I have heard before.

Mr. DIESCH. That is correct.

Senator BUNNING. Go right ahead.

Mr. DIESCH. First of all, let me tell you, there is a feeling that Fischer Tropsch requires coal. That is false.

Senator BUNNING. No, it does not. We know that.

Mr. DIESCH. You can produce it from natural gas, biomass, multiple products. Through the gasification process, the two products you want to produce the fuel are carbon monoxide and hydrogen, and that has to be in the proper ratio.

During the gasification process you also have an opportunity to clean up. It has to be very clean gas because you cannot have sulfur, you cannot have mercury, so you have to remove all those products, where in standard combustion, you do not remove it. It is much more expensive and difficult.

So you have removed all of the criteria pollutants out of the gas stream that makes the fuel, so that makes this a much cleaner fuel. If you look at the criteria pollutants that come off of combustion of this, it is 50 percent less overall on particulate matter, NOx, SOx, and there is no sulfur. That comes out of the fuel itself when you combust it.

So I know we have been talking a lot about the carbon dioxide side of things, but we ought to remember that this is a much cleaner fuel with the pollutants that are regulated today. That is another very positive thing with the fuel.

Senator BUNNING. Thank you, Mr. Chairman.

Senator BINGAMAN. Well, thank you very much.

Let me thank all of the witnesses. I think it has been very useful testimony. We will try to go through your written statements in detail and understand your points of view better before we proceed in this area. But again, thank you for being here, and that will conclude the hearing.

[Whereupon, at 2:39 p.m., the hearing was concluded.]

APPENDIX

ADDITIONAL MATERIAL SUBMITTED FOR THE RECORD

SENATE COMMITTEE ON FINANCE

SUBCOMMITTEE ON ENERGY, NATURAL RESOURCES AND INFRASTRUCTURE

HEARING ON COAL: A CLEAN FUTURE

April 26, 2007

Written Statement of
John Diesch
President of Rentech Energy Midwest Corporation

Thank you Chairman Bingaman, Senator Thomas and distinguished Committee members, I'm John Diesch, President of Rentech Energy Midwest Corporation (REMC), a subsidiary of Rentech. Rentech is the leading US firm developing facilities capable of commercial scale production of Fischer Tropsch fuels. These are ultra-clean diesel and jet fuels that can be made from any number of hydrocarbon rich resources, including coal, petroleum coke, natural gas, biomass and other abundant domestic sources.

This is a sample of our diesel – you will notice that it is virtually clear. It is extremely low in particulates and sulfur emissions. You can use Rentech diesel in any current engine that runs on conventional diesel – in trucks, buses, barges, locomotives or diesel cars. Last year, the Air Force flew a B52 bomber on the jet fuel version of FT. Our fuel produces all of the transportation energy of conventional fuels, with several major advantages:

- It can be made from abundant domestic natural resources, lessening our dependence on imported oil.
- It runs cleaner than conventional fuels from petroleum, producing slightly less greenhouse emissions than conventional diesel when used in the same engines. When compared to similar vehicles with gasoline internal combustion engines, there is about a 25 percent reduction in greenhouse gas emissions.
- For other regulated criteria emissions – SOx, NOx, and particulates – using our fuels cuts emissions by up to half over conventional diesel.
- Rentech diesel can also be stored 5 to 10 times longer than oil-derived diesel, and it is biodegradable, making it ideal for strategic reserves.

And let me state right up front that, with the proper manufacturing configurations and appropriate sequestering, we can manufacture our fuel so that the total production of greenhouse gases – from manufacturing AND vehicle use – is less than the wells to wheels emissions of conventional diesel. And that would be a major improvement over gasoline.

While the potential of this fuel is still in the early stages in the US, the technology for making this fuel is over 70 years old. Large scale manufacturing plants are operating in South Africa, Qatar, Malaysia, and under construction in a number of other countries including China, which is aggressively developing a CTL industry to meet its growing transportation fuel needs. In the US, Rentech holds over 20 patents from its more than 25 years of experience refining the process, and we expect to have the first commercial scale production facility operating in the US by 2010.

That first plant will be the conversion of the fertilizer plant in East Dubuque, Illinois that I have managed for nine years. Currently, we make nitrogen fertilizer and urea products for the local market, primarily serving farmers in Illinois, Iowa and Wisconsin within a 200 mile radius of the plant. Most fertilizer plants in the US are now struggling because of the sustained high cost of natural gas, the primary feedstock for making fertilizer products. In fact, over half of the US production of fertilizer has shut down in the last seven years, moving overseas where natural gas prices are significantly cheaper and more stable.

Let me demonstrate the clear and convincing economics. The East Dubuque plant uses 31,800 MMBtu per day, enough gas to heat a city of 100,000 homes. A ten cent increase in the price of natural gas is $1,000,000 per year in additional operating cost. This plant would have shut down three years ago if it was not for the conversion to clean coal technology.

So why add a fuel plant to a fertilizer plant? Because many of the processes are shared: the gasification of coal, the production of synthesis gas, the conversion of that synthesis gas into other useful products. Depending on the configuration and the additional equipment added, these plants can produce various combinations of fuels, fertilizers, electricity, and other useful manufacturing and consumer products.

Right now, we are in the final stages of design work at East Dubuque. We hope to break ground in just a matter of months, and it will take about 3 years to convert the existing fertilizer manufacturing process to a coal-fed gasification system and add an FT plant to also produce fuels. After conversion, we will increase ammonia production capability from 830 tons per day to 1,000 tons per day while producing 1,200 to 2,000 barrels per day of ultra clean FT fuels, with the possibility of ramping up to over 5,000 barrels per day. Our construction schedule anticipates the plant operating in the new configuration by 2010, making it the first commercial scale plant in the US producing these fuels

The conversion will take an investment approaching 1 billion dollars. It will nearly double the number of full-time high-paying union jobs currently at the plant, and employ nearly 1,000 construction workers at its peak. REMC is the highest paying employer in the Greater Dubuque area.

Rentech is doing more than just building a first-of-its-kind plant, saving jobs, saving an industry and creating a new domestic fuel source. We are a company that is also committed to doing what is right. That is why we have been examining the ways that we can reduce the greenhouse gas footprint of these plants. Using coal as a primary feedstock has many positive attributes – it allows us to sustain the domestic manufacture of fertilizer, it creates additional jobs in the American coal industry, and it is an abundant local resource being utilized effectively and cleanly. At the same time, using coal does create more greenhouse gases – but the great advantage of the technology is that those greenhouse gases can be contained during manufacture.

Fertilizer plants capture and sequester carbon dioxide in their products. At East Dubuque we use some of the carbon to manufacture our UREA and fertilizer products, where it helps fuel the growth of the food crops that dominate our region of the Midwest, most notably corn. Next, we capture additional CO_2 produced during manufacturing, clean it and compress it, and sell it to the food and beverage industry. We will continue with our capture program after the conversion, but the extent of those carbon solutions are unique to East Dubuque and the co-production of fertilizer and FT fuels.

For our future proposed projects, Rentech's engineers are working on recycling configurations that maximize the capture of CO_2 during manufacturing. Our second proposed plant, in Natchez, Mississippi, is near oil fields where Enhanced Oil Recovery would allow productive use and sequestration of all of the CO_2 captured. The potential for carbon capture and sequestration is also a critical factor in our consideration of the potential of other future sites. Rentech is focusing our development efforts on projects with realistic CO_2 capture and sequestration opportunities.

As capture rates approach 80-85 percent, the total wells-to-wheels emissions of our diesel is comparable to conventional diesel – and a marked improvement over gasoline. Remember – in usage, our diesel actually emits less carbon dioxide per mile than conventional diesel. And there are early projections that mixing in 10 percent biomass with the feedstock could result in even more noticeable reductions in greenhouse gases.

A couple of quick statistics – if every vehicle on the road today were using a diesel engine, run on FT fuel manufactured with 80 percent carbon capture and 10 percent biomass, we would reduce the transportation emissions from those vehicles by 5-6 percent over conventional diesel – and 30 percent or more over gasoline. If we switched to diesel hybrid engines – using technologies available today, not waiting to be invented – we could reduce greenhouse gas emissions by well over half in those same vehicles compared to using gasoline engines. And let me be clear – I am talking total emissions – wells to wheels. That is the potential of these fuels and this process.

The investment that is required to make good on this promise though, is tremendous. I mentioned already that it will cost nearly a billion dollars to convert the East Dubuque fertilizer plant. Plants with a bigger production capacity built from scratch would cost even more. And the additional costs to ensure that we are optimizing carbon capture and sequestration can be significant as well.

While Rentech is developing our plants – at East Dubuque and beyond – primarily with private capital investments, active support from both the state and federal governments is critical to developing this industry. We were able to move East Dubuque forward because of initial feasibility study help from the State of Illinois. As we developed potential financing packages for the conversion to industrial gasification, we hoped to use the provisions of EPAct 2005, including the 48B investment tax credit.

As you know, however, the 48B program was capped at $350 million last year. And it was oversubscribed – dramatically. Applications totaled $2.7 billion. Unfortunately, that meant that a lot of great applications, like ours, didn't get any funding at all. Although it is not completely clear because some of the awards were kept secret, it seems that most of the funding went to traditional applications – not the sort of technological advances that could represent breakthrough new gasification industries for the US.

From that experience, we draw two complementary recommendations – first, raise the cap on the credit so that more projects, especially those that could revolutionize the industry, can be funded. We strongly recommend a significant increase of at least double or more. Second, specifically clarify that gasification tied to FT is a permissible use. In fact, we would suggest that the Congress consider designating a specific portion of the industrial gasification tax credit to FT development.

One of the most important potential users of our diesel and jet fuels is the U.S. military. The strategic advantages to a stably-priced domestic source of fuel that has all of the built in advantages of FT – storage life, biodegradability, and reduced emissions – are obvious. In fact, some of the biggest reductions in potential emissions – both greenhouse gases as well as regulated criteria emissions – have been noted in tests in military vehicles. We appreciate Congressional support for longer-term military contracting authority that would allow for the kind of stable investment climate to start up these plants.

Next, we must recognize that finding appropriate means to capture and sequester greenhouse gases is a critical challenge for every major heavy industry in our country and indeed around the world. We have two additional recommendations that could help ensure that the United States remains competitive in a carbon-constrained world – and indeed, that our nation leads the way environmentally. First, recognize that advances in carbon sequestration options have applications across a wide range of industries and fund basic research into promising applications. Second, offer incentives for companies – like Rentech – that are taking the lead and including carbon capture and sequestration technologies in their plant designs.

Two tax incentives – an FT-specific variant on 48B and a deduction for the cost of carbon capture and sequestration equipment – paired with longer military contracting authority could set the stage for rapid development of this industry and have far-reaching consequences for our national security. We could more effectively utilize domestic resources. We could reduce our dependence on foreign oil, with all the associated consequences -- diplomatic, economic and military. And we could maintain key industrial sectors in a way that is far more beneficial to the long-term stability of our environment.

And finally, I'd like to throw in one more potential advantage that is unique to what we are doing in East Dubuque. At that plant we are really producing two fuels – one for transportation, the other for our food crops in the form of the fertilizers that are necessary for their growth. As our nation meets the economic and environmental challenges of this new century, we can't afford to lose our independence in either area. So I issue an invitation to each of you and your staffs – anytime you would like to see what we are doing, please come. We are proud of our products, proud of workforce, and proud that we are a good neighbor to the Mississippi River and to our local communities.

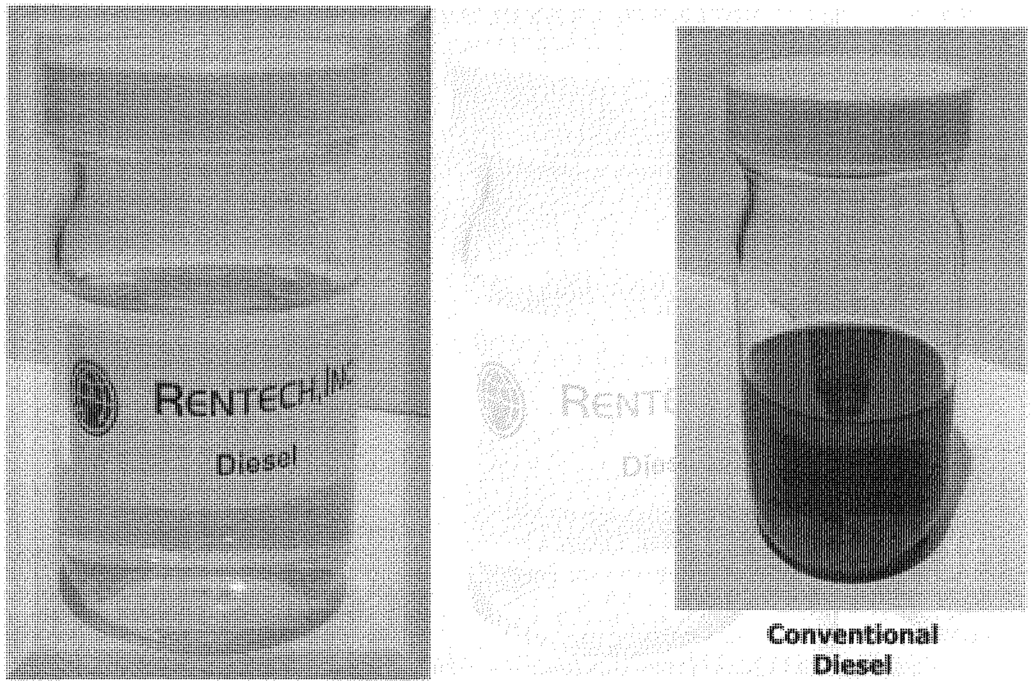
Thank you very much for your time this afternoon.

RENTECH ENERGY
MIDWEST

Recommendations

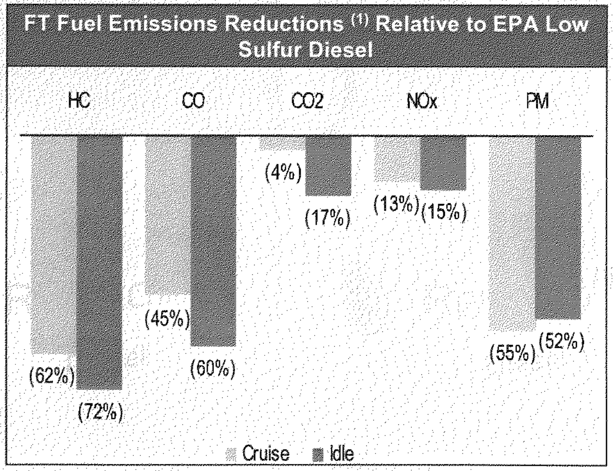
1. Fund the industrial gasification Investment Tax Credit and include FT specifically;
2. Increase the tax credit for carbon capture and sequestration; and
3. Support long term contracting authority for the U.S. military.

Rentech's FT Diesel

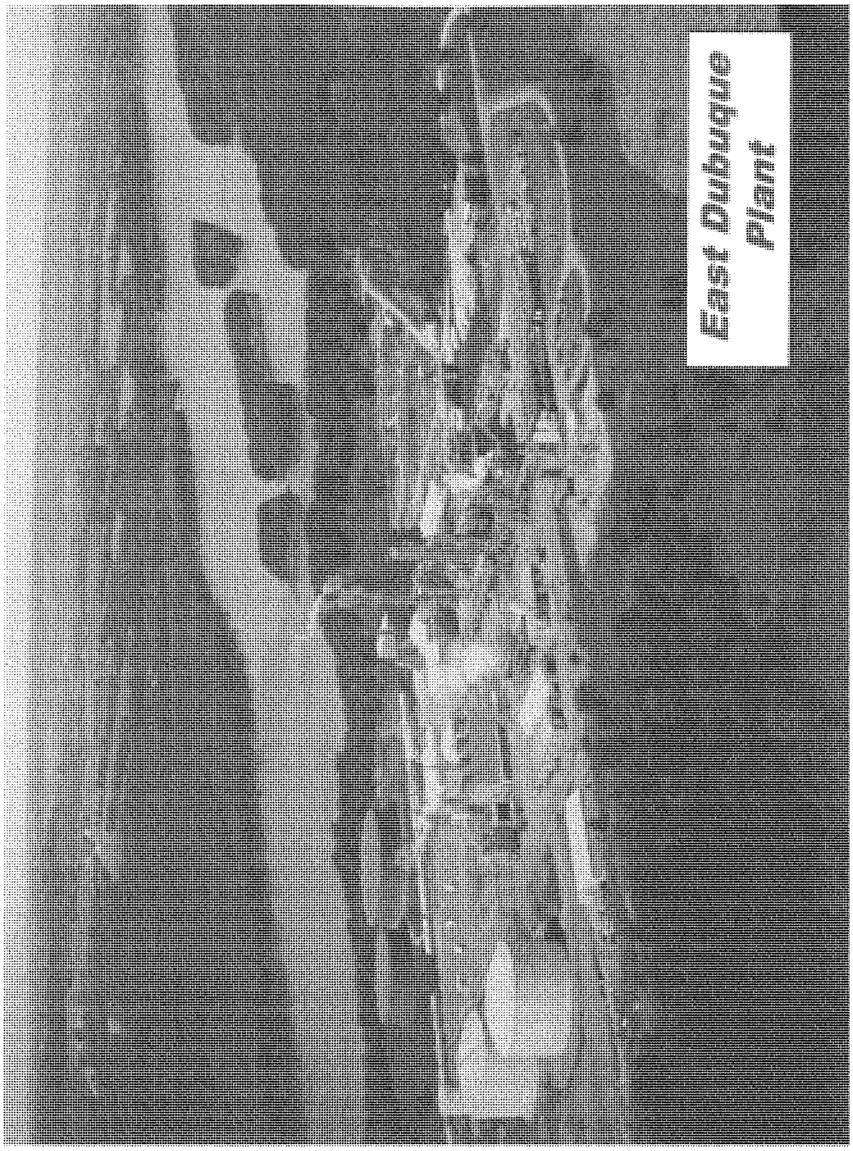


Conventional
Diesel

Rentech's FT Diesel


FT Fuel Emissions Reductions (1) Relative to EPA Low Sulfur Diesel

(1) HC = Hydrocarbon, CO = Carbon Monoxide, $C0_2$ = Carbon Dioxide, $N0_x$ = Nitrogen Oxide, PM = Particulate Matter. Data from U.S. Military testing.


East Dubuque
Plant

World Natural Gas Prices $/MMBtu

RENTECH ENERGY
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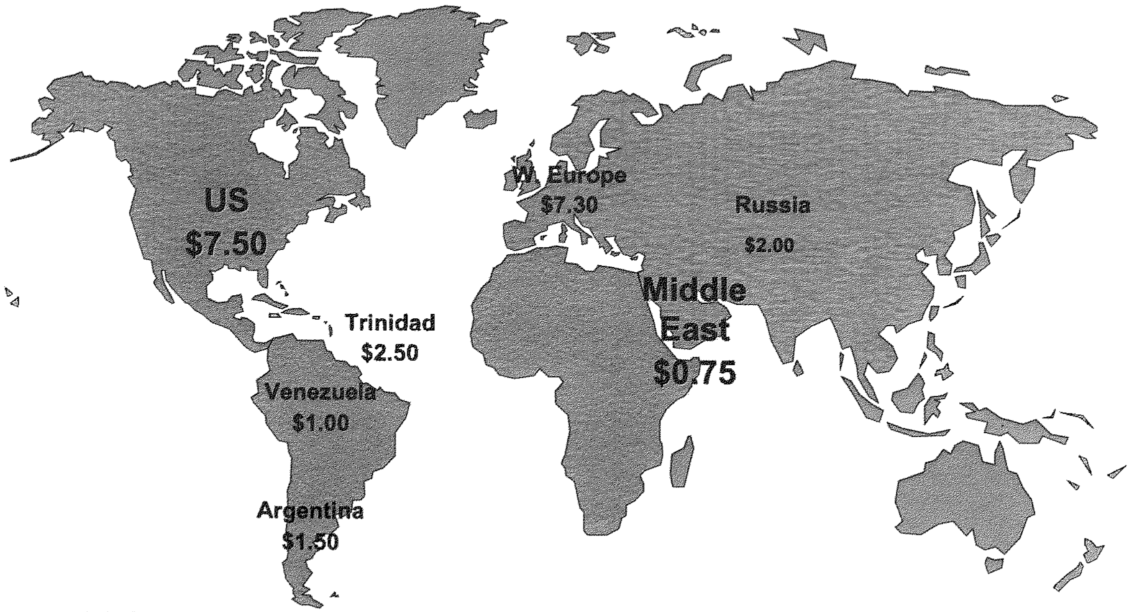


PCS 2007 Est.

Environmental Performance Characteristics of Fischer-Tropsch Fuels

Abstract

Fischer-Tropsch (FT) diesel and jet fuels can be produced from a variety of abundant American resources -- coal, petroleum coke, biomass, solid wastes, and natural gas – in a manner that produces significant environmental benefits over similar fuels derived from imported oil. In vehicle usage, FT fuels emit fewer greenhouse gases per mile than conventional gasoline, diesel, or jet fuels. Diesel engines run on FT yield large reductions in all criteria emissions (particulate matter, nitrogen oxides, carbon monoxide, and hydrocarbons). When manufacturing processes are designed to maximize carbon capture and storage, FT fuels produce total greenhouse gas emissions (carbon dioxide, carbon monoxide, nitrogen oxides, and hydrocarbons) that are comparable to or better than "wells-to-wheels" emissions of fuels from oil. Using biomass as a portion of the feedstock can create a greenhouse gas emissions footprint dramatically smaller than conventional fuels. Because FT fuels can be used in legacy, current and advanced diesel or turbine engines without modification to the engine, transported using existing infrastructure, and blended in any proportion with conventional fuels, they are uniquely poised to play a significant role in reducing U.S. dependence on foreign oil in an environmentally beneficial manner.

Introduction

The chemistry underlying Fischer-Tropsch (FT) fuels was developed in 1923 in Germany by Professor Franz Fischer and Dr. Hans Tropsch. In the process, synthesis gas which is predominantly composed of carbon monoxide and hydrogen is passed by a catalyst (usually cobalt or iron), forming hydrocarbon chains and water. In the most basic form, the synthesis reaction can be written as $CO + 2H_2 > CH_2 + H_20$. The hydrocarbon chains yielded by the FT synthesis will be of various lengths (CH_4, C_2H_6, C_3H_8, etc.) and exit the reaction as liquid hydrocarbons (including paraffinic or olefinnic waxes, which are common household and manufacturing materials). The liquid hydrocarbon product from the FT synthesis is high quality, with almost no sulfur, nitrogen and aromatic impurities, making it an ideal hydrogen-rich source for producing low-emission, clean-burning fuels.

Synthesis gas to feed into the FT reactor can be gasified from any number of carbon-bearing resources, including natural gas, coal, petroleum coke, solid wastes and biomass. Gasification systems are optimized for different feedstock resources, but a characteristic of all current commercially-available systems is that the more consistent the feedstock is, the more efficient and stable is the process of synthesis gas conversion. The syngas produced is essentially identical no matter which feedstock is used.

Once the syngas has been transformed into FT liquids, a number of refining routes can be used to transform the FT product into usable fuels. Those clean fuels include naphtha, premium diesel, and ultra-clean jet fuel. Because the FT reactor process is corrupted by the presence of contaminants such as sulfur and aromatics, those elements must be removed before the syngas is passed through the FT reactor and are thus reduced significantly in the premium FT fuels that are produced.

Characteristics of FT Fuels

FT diesel and jet fuels are non-toxic, water white, highly pure hydrocarbons. They are biodegradable. They are chemically stable and can be stored for extended periods of times. While FT fuels can be stored for years, conventional diesel and oil-derived fuels begin to decompose in a matter of months. FT fuels are therefore ideal candidates for strategic reserves for both military and domestic first responder use.

Compared to conventional fuels, FT fuel has a lower density due to the lack of aromatics, and a higher heating (BTU) value due to the higher hydrogen content. There is also a slightly lower carbon content than conventional diesel. The direct comparisons, from a peer-reviewed study by Southwest Research Institute, are:

Property	**Conventional Diesel Fuel**	**FT Diesel Fuel**
Carbon Content	86.82%	84.69%
Hydrogen Content	13.18%	15.31%
Net Heating Value, BTU/lb	18,400	18,900
Density, g/mL	0.84	0.77

Source: Southwest Research Institute.

A joint study by major European automakers and Institut Francais du Petrole (IFP)[1] presented in 2007 reported similar heating values and density, and also included more detailed analysis of additional characteristics:

Property	**Conventional Diesel Fuel**	**FT Diesel Fuel**
Cetane Number	55	>75
Cetane Index	58	>82.5
Heating Value, MJ/kg	42.85	43.59
Density, @ 15oC, Kg/m3	841.7	775.4
Viscosity, @ 40oC, mms2/s	3.675	2.197
Sulfur, Mg/kg	42	18
Total Aromatics	39.4%	0.5%

Source: ACEA-Eucar[2]

The higher cetane values (which are similar to octane values in gasoline) and heating values reflect that FT diesel contains higher energy content than conventional diesel. FT fuels have a slightly lower density than conventional diesel, requiring a volumetric increase of 7-8% to operate a typical diesel engine; diesel powered vehicles, however, enjoy a 20-30% or more fuel consumption advantage over gasoline internal combustion engines. Because emissions are based on the mass of fuel consumed, not the volume, and because FT diesel enjoys both a higher energy value content and drastically lower contaminant levels, using FT diesel results in markedly lower emissions per mile driven than conventional diesel.

Conclusion 1: FT diesel offers significant advantages over conventional diesel.

Criteria Emissions

The study conducted by Southwest Research Institute[3] found a wide range of emissions reductions for FT diesel relative to EPA Certification Diesel Fuel, depending upon the engine used, driving conditions, and other study parameters. All greenhouse gas emissions were reduced, including carbon dioxide. Those representative emissions benefits were:

Emission	**Range of Reduction for FT Fuel vs. EPA Certification Diesel**
Particulate Matter (soot)	20-60%
Nitrogen Oxides (NOx)	5-20%
Carbon Monoxide (CO)	20-50% *
Hydrocarbons (HC)	25-50% *
Carbon Dioxide (CO_2)	3-4%

Source: Southwest Research Institute ** VW studies show bigger cuts*[4]

A study by the U.S. Army evaluating 6L diesel engines in off-road military vehicles yielded similar results:

Emission	**Reduction at Idle** **FT diesel vs. EPA Low Sulfur Diesel**	**Reduction at Cruise** **FT diesel vs. EPA Low Sulfur Diesel**
Particulate Matter (soot)	55%	52%
Nitrogen Oxides (NOx)	13%	15%
Carbon Monoxide (CO)	45%	60%
Hydrocarbons (HC)	62%	72%
Carbon Dioxide (CO_2)	4%	17%

Source: U.S. Military Testing Data[5]

According to the 2007 IFP study[6], FT fuels "show a very high potential for reducing CO, HC, and PM emissions, as well as for realizing a much more favorable NOx/PM trade-off without the commonly observed associated penalties in fuel efficiency." Additional real world driving tests by Sasol (vehicles driven from South Africa to Qatar) and VW/Shell (vehicles driven on-road in Germany)[7] found criteria emission reductions in the same range. All greenhouse gas emissions were reduced, and there was a consistent 2-4% reduction in CO_2 from the tailpipe.

Conclusion 2: FT diesel yields significant reductions in all criteria emissions over conventional diesel, in some cases exceeding cuts of half or more.

Conclusion 3: In vehicle usage, FT diesel offers a small reduction in direct CO_2 emissions over conventional diesel, as well as emission reductions in all other greenhouse gases.

Vehicle Usage: Greenhouse Gas Emissions Comparison of FT Diesel to Gasoline

In 2004, a study was conducted for Toyota[8] by Mizuho Research Institute in Japan that compared greenhouse gas emissions of a wide range of conventional and alternative fuels, including FT fuels made from coal (without carbon capture and storage). The summary chart from that report, available at www.mizuho-ir.co.jp/english, was captured from the Institute's website and is reproduced below:

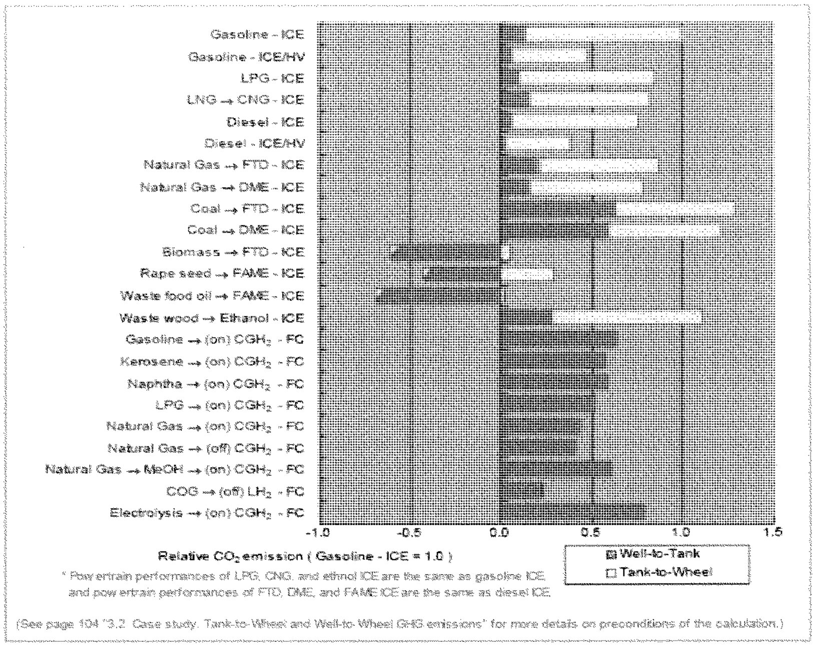
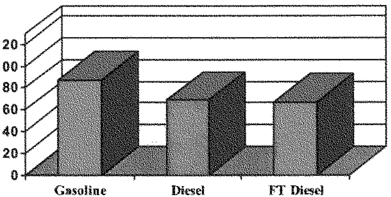


Figure Well-to-Wheel GHG emissions under fixed conditions of driving sedan type vehicles
Source: Mizuho Research Institute[9]

That report breaks down the total greenhouse gas emissions into production components ("well-to-tank") and vehicle usage ("tank-to-wheel"), and uses gasoline as the standard for comparing all other fuels. The evaluation was based on a four-door sedan, and on vehicle miles driven. The total emissions of greenhouse gases (GHG) were measured, using a CO_2 equivalency (where all gases are converted to the equivalent impact of CO_2 to standardize measurements for comparisons). For every gram of CO_2-equivalent GHG emissions from gasoline, 0.13g came from production (drilling, refining, and transportation) and 0.87g came from vehicle use (emitted from the tailpipe after combustion). To travel the same distance that it took for a gasoline internal combustion engine to emit 1g of GHG (total, "wells-to-wheels"), a conventional diesel engine would emit 0.75g of GHG, a 25% reduction overall.

Comparing only vehicle usage figures ("tank-to-wheel"), diesel emits 0.69g to travel the same distance as gasoline (0.87g), a 21% reduction in emissions from the tailpipe. The same vehicle using FT Diesel made from coal (labeled "Coal > FTD-ICE" on the graph on the previous page) would emit 0.67g of GHG in the same distance, a 3% reduction over conventional diesel and a 23% reduction over gasoline. Those figures for tailpipe emissions are consistent with the real world tests referenced earlier.

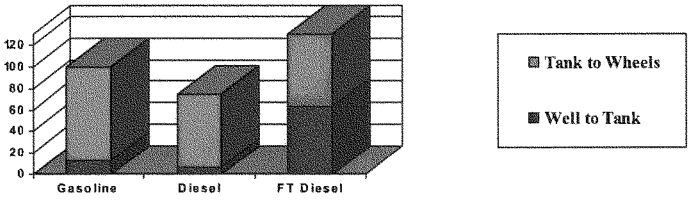
Comparative Greenhouse Gas Emissions from Vehicle Usage



Source: Mizuho Research Institute[10]

The wells-to-wheels emissions for FT Diesel made from coal, however, are higher (1.3g for FT diesel, compared to gasoline's 1.0g and conventional diesel's 0.75g). Those figures are for FT Diesel made from coal without any capture, mitigation or sequestration of greenhouse gases during manufacture.

Total Greenhouse Gas Emissions: NO Carbon Capture or Storage



Source: Mizuho Research Institute[11]

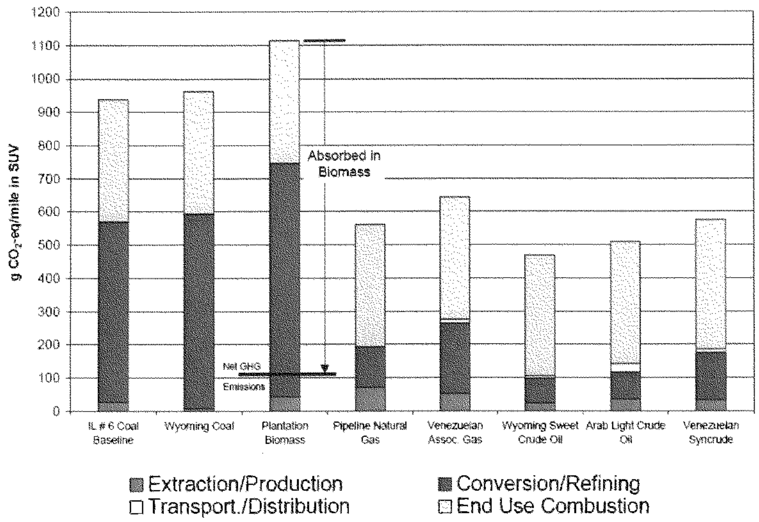
Based on the figures established for the Toyota study[12], capturing and storing 48% of the greenhouse gas emissions during manufacturing would make FT Diesel equivalent to overall gasoline GHG emissions, and capturing and storing 87% would make FT Diesel equivalent to overall greenhouse gas emissions from conventional diesel.

Conclusion 4: In vehicle usage, FT Diesel significantly outperforms gasoline on total greenhouse gas emissions.

Conclusion 5: Manufacturing FT Diesel from coal requires mitigation of greenhouse gases to be comparable to similar emissions for conventional fuels.

FT Diesel and FT Jet Fuel: Reducing Emissions from Production

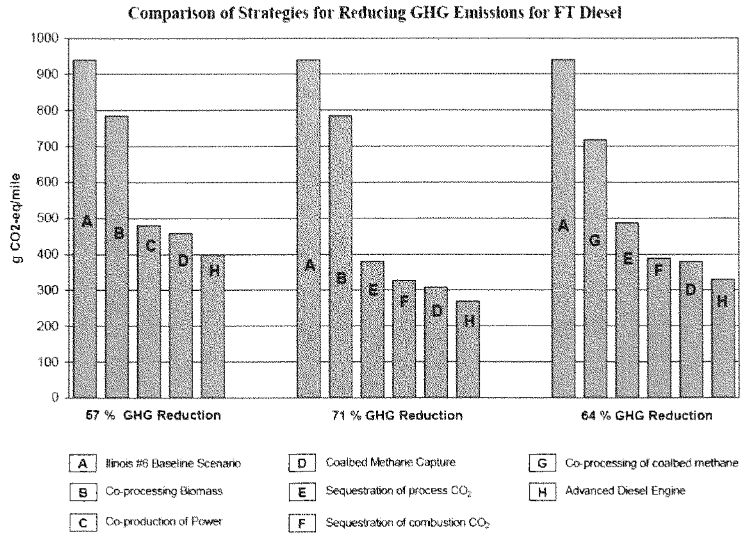
A U.S. Department of Energy National Energy Technology Laboratory (NETL) report[13] titled "Life-Cycle Greenhouse-Gas Emissions Inventory for Fischer-Tropsch Fuels" by John Marano and Jered Ciferno makes a comparison similar to the Toyota study. This report, produced in 2001, made several specific assumptions about the wells-to-wheel greenhouse gas analysis (including hypothetical locations of production plants) and also converted all greenhouse gas emissions to CO_2 equivalencies. As in the later Toyota study, the basis for all estimates was vehicle-miles driven, but instead of utilizing figures for a four-door sedan, the values were for a sport utility vehicle (SUV). Different baseline assumptions resulted in the NETL report attributing a higher level of greenhouse gas emissions to production. This chart also assumes that there is no carbon capture and storage during FT production.


Full Life-Cycle GHG Emissions for FT & Petroleum Diesel Scenarios

Source: U.S. Department of Energy, National Energy Technology Laboratory (NETL)[14]

The figures in the NETL report[15] assumed that FT Diesel produced about the same greenhouse gas emissions in vehicle usage as conventional diesel (around 368g CO_2-eq/mile in an SUV); as noted earlier, both theoretical studies and real world data show a 3% or more differential in favor of FT Diesel. The total "wells-to-wheels" greenhouse gas emissions of FT Diesel made from Illinois #6 coal were 939g CO_2-eq/mile, compared to 509g CO_2-eq/mile for conventional diesel made from Arab Light Crude. Light crudes are becoming less available and heavy crudes (with higher emissions) are becoming the norm, but this paper will use the Arab Light Crude figures for comparison.

The NETL report[16] assumptions resulted in 543g CO_2-eq/mile of greenhouse gas emissions being attributed to manufacturing (the "Conversion/Refining" figures on the graph). To be equivalent to the total greenhouse gas emissions from conventional diesel refined from Arab Light Crude, 79% of the greenhouse gases (almost exclusively CO_2) produced during manufacture of FT Diesel would need to be captured and stored. In the NETL report, Marano-Ciferno demonstrated that simple efforts to capture and sequester CO_2 will lead to total greenhouse gas (GHG) emissions for FT fuels below that of conventional fuels.



Source: U.S. Department of Energy, National Energy Technology Laboratory (NETL)[17]

The above chart shows numerous ways in which GHG emissions can be reduced for FT fuel production. For the comparisons above, a GHG reduction of 46% overall (to 509g CO2-eq/mile) would make total greenhouse gas emissions from FT equivalent to the total GHG emissions produced from diesel refined from Arab Light Crude, so each scenario pictured reduces GHG from FT significantly below conventional diesel. Marano-Ciferno[18] assumed that only 55% of CO_2 from manufacturing would be captured and stored ([E] in the graphs above). Since 2001, however, technology process designs have improved. Recent designs that recycle gases through the FT reactor allow for CO_2 capture rates from gasification and FT processing approaching 80% levels – the levels required to be equivalent to total GHG of diesel from Arab Light Crude and to be better than diesels made from heavy crude according to the NETL report.

Conclusion 6: CTL and FT process designs that maximize CO_2 capture during manufacture of FT Diesel can reduce total greenhouse gas emissions to levels at or below conventional diesel (and far below gasoline).

FT Diesel from Coal and Biomass – Dramatic Reductions in CO_2 Emissions

From Nature, Vol. 444, 7 December 2006[19]:

> ***"...there is still the appealing option of spiking coal feedstock with biomass. Coupled with carbon sequestration, this would reduce greenhouse gas emissions without requiring much change to existing technology, says Robert Williams, a researcher at Princeton University's Environmental Institute. Williams has calculated that a mixture of 89% coal and 11% biomass could reduce carbon emissions by 19% relative to using the same process with coal only."***

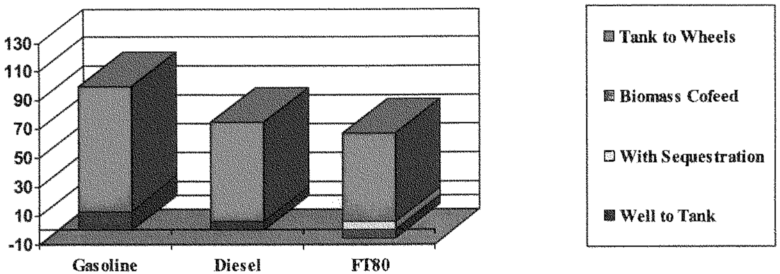
A number of recent scientific papers[20] have outlined the benefits of producing synthesis gas from biomass, and the potential for dramatically reducing overall greenhouse gas emissions by co-processing coal and biomass through gasification and the FT process. A 100% biomass gasification system that included full sequestration during manufacturing would have a net negative overall GHG emissions profile – meaning that cars driving on FT fuel produced from such a system could actually be responsible for a net reduction of greenhouse gases, even though they emitted CO_2 at the same rate as conventional diesel. At the current time, however, a 100% biomass system is not economically feasible, and the variation in biomass makes a stable gasification process exceptionally difficult. There are also a number of questions that have been raised about the net energy value of some forms of biomass, given the energy content that goes into raising, harvesting and transporting crops.

Nonetheless, Robert H. Williams and Eric D. Larson of the Princeton Environmental Institute of Princeton University have demonstrated[21] over the past year that including biomass in the feedstock of an FT process, even in relatively small percentages, can yield a significant reduction in the GHG profile of both the manufacturing process and the fuel produced. In the June 2006 paper[22] titled "Synthetic fuels in a world with high oil and carbon prices," Williams, Larson and their colleague Haiming Jin from TX Energy concluded:

> "With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, *to near zero*, via co-processing biomass and coal with CCS so as to exploit the negative emissions of storing photosynthetic CO_2." (Emphasis added.)

Even using far more conservative estimates for the potential greenhouse gas reduction achievable, adding as little as 10% biomass to a predominantly coal feedstock can significantly reduce the total GHG emissions of FT fuels. The chart on the next page demonstrates the effect when biomass is included in the calculations of the Toyota study (which required higher sequestration levels during manufacturing than the NETL study to achieve parity with conventional diesel). Since the Toyota study did not include a coal plus biomass mix, NETL data on co-processing with biomass was converted proportionally for that comparison.

Total GHG Emissions: FT with 80% CCS and Biomass Co-feed



Source: Mizuho Research Institute, including NETL data[23]

When FT fuels are produced with 80% carbon capture and storage during manufacturing, and the conservative biomass co-feed GHG reductions utilized in the NETL study[24] are combined, the total "wells-to-wheels" GHG emissions drop to almost 10% below conventional diesel and are more than 30% below the identical vehicle with a gasoline internal combustion engine. If the figures cited by Robert Williams in the Nature article[25] quoted on the previous page are used, the total GHG emissions of FT Diesel made predominantly from coal drops to nearly 15% below conventional diesel and almost 40% below gasoline.

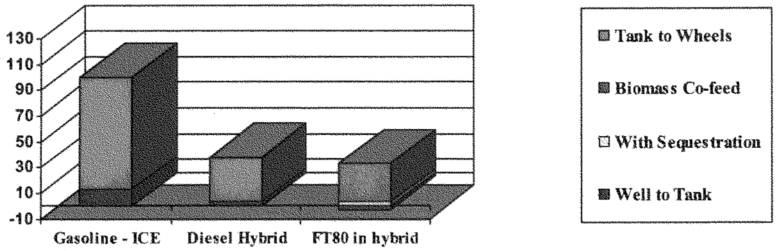
Conclusion 7: When carbon capture and storage are maximized during manufacturing, and a small percentage of biomass is included as a co-feed, FT Diesel made predominantly from coal has significantly smaller GHG emission levels than conventional fuels derived from oil.

Advanced Diesel Engines and Hybrids

In the NETL chart[26] comparing strategies for reducing GHG emission of FT Diesel reproduced on page 7 of this paper, the final step of every strategy was to utilize the fuel in an Advanced Diesel Engine. The IFP report[27] reinforced the potential for achieving additional reductions in emissions by improving engine technology, noting that FT fuels have "…still-unexploited potential for extraordinary reductions of exhaust emissions if the engine control software is optimized and easily accessible engine parameters are recalibrated, e.g. EGR rate and injection timings."

The Toyota study confirmed that gasoline hybrid engines could reduce GHG emissions by more than 50% over standard internal combustion engines, and that diesel hybrids could achieve similar reductions. The chart[28] reproduced on page 4 of this paper demonstrates that conventional diesel fuel utilized in a diesel hybrid has more than 60% less total GHG emissions than gasoline used in a standard internal combustion engine. When FT Diesel that is manufactured with 80% CCS and biomass co-feed is used, the total GHG emissions reduction over gasoline internal combustion engines exceeds 65%.

Total GHG Emissions: FT Diesel with 80% CCS & Biomass in a Hybrid Engine



Source: Mizuho Research Institute, including NETL data[29]

The hybrid technologies examined in the Toyota study were commercially-available diesel hybrid engines. It is easy to project that advanced hybrids that are calibrated specifically for FT Diesel could approach or exceed a 70% reduction in total GHG emissions over a gasoline internal combustion engine in the same vehicle, when the FT Diesel is manufactured to maximize CO_2 reductions.

Conclusion 8: Using hybrid technology available today and manufacturing FT Diesel to optimize CO_2 reductions, FT fuels from coal could achieve emissions reductions that significantly exceed the goal of cutting transportation emissions by half over today's gasoline internal combustion engines.

Concluding Notes

FT fuels manufactured from abundant American resources hold great promise. They can help reduce U.S. dependence on imported oil, while simultaneously offering significant environmental advantages. For criteria emissions, those advantages include some cuts of more than half in existing engines without modification. For greenhouse gas emissions, the unique capabilities of capturing CO_2 in the manufacturing process – both in gasification and FT synthesis – means that fuels could be produced that significantly reduce total "wells-to-wheels" GHG emissions over conventional fuels.

FT fuels must be made with extremely low sulfur contents because of the negative effects of sulfur in the FT reactor. Removing sulfur from fuels, however, also reduces lubricity. FT Diesel can be mixed with a number of other conventional or alternative fuels to counter that effect. Adding approximately 5-10% biodiesel, for example, would restore the lubricity properties of ideal fuels. That will help grow the market for biodiesel, and further reduce the overall GHG emissions of FT fuel.

Combining the potential of FT with the inherent GHG reductions achievable with biomass can offer even greater promise. Currently, 100% biomass FT processes are not feasible, because of the inherent variation in biomass (which impedes the consistency that allows gasification systems to be optimized) and because of the quantities of biomass which would be required (which eliminates some of the GHG emissions profile gains because of transportation and other production costs). The combination of biomass with fossil resources however allows production of FT fuels to achieve the best of both – the economic prices of abundant resources and the GHG emissions reductions of biomass. It also helps to jump-start a new component of the biofuels industry, to develop the technology base for potentially increasing the biomass percentages in FT fuels, and to increase the potential that 100% biomass systems with net negative GHG emissions could be feasible in the future.

All of this can be done in the context of current engines, current distribution systems, and current technology. While there are many proposals for reducing greenhouse gases from transportation use, one of the major stumbling blocks to achieving the goals set forth is the reluctance of the public to adopt new technologies and unproven systems. The incremental achievements that can be achieved with FT, and the potential for even greater improvements as FT systems are developed, offer a significant short-term improvement and could provide the impetus for even greater long-term change.

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[1] Joint study by European automakers and Institut Francais du Petrole (IFP), (SAE 2007-01-0035), presented to Society of Automotive Engineers, meeting in South Africa in 2007. Cited by Diesel Fuel News, Vol. 11, Issue 6, 12 March 2007. www.worldfuels.com.

[2] Ibid.

[3] Southwest Research Institute.

[4] From page 22 of the report "Synthesis Gas from Biomass for fuels and chemicals," prepared for the International Energy Agency (IEA) from proceedings of the May 2005 SYNBIOS Conference in Stockholm, Sweden by A. van

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der Drift and H. Boerrigter, January 2006: *"Volkswagen focuses on Fischer-Tropsch diesel as the second generation biofuel. It is called "sunfuel" or "sundiesel" [16]. This is chemically identical to Fischer-Tropsch diesel ("synfuel") made from gas (GtL) or coal (CtL). Fleet tests performed by Volkswagen with Fischer-Tropsch diesel show significant improvements compared to conventional low-sulphur fossil diesel. CO and hydrocarbon emissions reduced by 91% and 63%. The emission of particulates reduced by 26% and even NOx was reduced by 6% [55]. These improvements add up to the original CO_2-emission reduction argument to use biomass-based Fischer-Tropsch diesel (sunfuel). Renault has also performed tests where the reduction of soot emissions was shown when Fischer-Tropsch diesel was used compared to fossil diesel [55]."* The cites [16] and [55] refer to specific papers presented at the conference.

[5] Data from U.S. Army tests.

[6] Joint study by European automakers and Institut Francais du Petrole (IFP), (SAE 2007-01-0035), presented to Society of Automotive Engineers, meeting in South Africa in 2007. Cited by Diesel Fuel News, Vol. 11, Issue 6, 12 March 2007. www.worldfuels.com.

[7] "Synthesis Gas from Biomass for fuels and chemicals," prepared for the International Energy Agency (IEA) from proceedings of the May 2005 SYNBIOS Conference in Stockholm, Sweden by A. van der Drift and H. Boerrigter, January 2006.

[8] "Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context", prepared for Toyota Motor Corporation by Mizuho Information & Research Institute, Inc., November 2004. www.mizuho-ir.co.jp/english/.

[9] Ibid.

[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] "Life-Cycle Greenhouse -Gas Emissions Inventory For Fischer-Tropsch Fuels" Prepared for US Department of Energy National Energy Technologies Laboratory (NETL) by Energy and Environmental Solution, LLC, John J. Marano and Jared P. Ciferno, June 2001.

[14] Ibid.

[15] Ibid.

[16] Ibid.

[17] Ibid.

[18] Ibid.

[19] "Making it up as you go along. Chemists can make liquid fuel from biomass – or from coal," article authored by Heidi Ledford, Nature, Vol. 444, 7 Dec 2006.

[20] "Synthesis Gas from Biomass for fuels and chemicals," prepared for the International Energy Agency (IEA) from proceedings of the May 2005 SYNBIOS Conference in Stockholm, Sweden by A. van der Drift and H. Boerrigter, January 2006.

"Gasification-Based Biorefineries Integrated with Pulp Mills," a presentation to the First Wednesday Seminar at Resources for the Future, Washington, DC by Eric D. Larson of the Princeton Environmental Institute, Princeton University, 4 April 2007.

"Synthetic fuels in a world with high oil and carbon prices," a paper prepared for the 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, by Robert H. Williams, Eric D. Larson, and Haiming Jin of the Princeton Environmental Institute, Princeton University and TX Energy, Houston, TX, June 2006.

[21] "Gasification-Based Biorefineries Integrated with Pulp Mills," a presentation to the First Wednesday Seminar at Resources for the Future, Washington, DC by Eric D. Larson of the Princeton Environmental Institute, Princeton University, 4 April 2007.

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[23] Combination of data from "Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context", prepared for Toyota Motor Corporation by Mizuho Information & Research Institute, Inc., November 2004. www.mizuho-ir.co.jp/english/, and "Life-Cycle Greenhouse –Gas Emissions Inventory For Fischer-Tropsch Fuels" Prepared for US Department of Energy National Energy Technologies Laboratory (NETL) by Energy and Environmental Solution, LLC, John J. Marano and Jared P. Ciferno, June 2001.

[24] "Life-Cycle Greenhouse –Gas Emissions Inventory For Fischer-Tropsch Fuels" Prepared for US Department of Energy National Energy Technologies Laboratory (NETL) by Energy and Environmental Solution, LLC, John J. Marano and Jared P. Ciferno, June 2001.

[25] "Making it up as you go along. Chemists can make liquid fuel from biomass – or from coal," article authored by Heidi Ledford, Nature, Vol. 444, 7 Dec 2006.

[26] "Life-Cycle Greenhouse –Gas Emissions Inventory For Fischer-Tropsch Fuels" Prepared for US Department of Energy National Energy Technologies Laboratory (NETL) by Energy and Environmental Solution, LLC, John J. Marano and Jared P. Ciferno, June 2001.

[27] Joint study by European automakers and Institut Francais du Petrole (IFP), (SAE 2007-01-0035), presented to Society of Automotive Engineers, meeting in South Africa in 2007. Cited by Diesel Fuel News, Vol. 11, Issue 6, 12 March 2007. www.worldfuels.com.

[28] "Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context", prepared for Toyota Motor Corporation by Mizuho Information & Research Institute, Inc., November 2004. www.mizuho-ir.co.jp/english/.

[29] Combination of data from "Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context", prepared for Toyota Motor Corporation by Mizuho Information & Research Institute, Inc., November 2004. www.mizuho-ir.co.jp/english/, and "Life-Cycle Greenhouse –Gas Emissions Inventory For Fischer-Tropsch Fuels" Prepared for US Department of Energy National Energy Technologies Laboratory (NETL) by Energy and Environmental Solution, LLC, John J. Marano and Jared P. Ciferno, June 2001.

Prepared for 8th *International Conference on Greenhouse Gas Control Technologies*, Trondheim, Norway, 19-22 June 2006

Synthetic fuels in a world with high oil and carbon prices

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Abstract

Four carbon management options are investigated for making Fischer-Tropsch fuels plus electricity: three processing coal and one co-processing coal and biomass. Energy and carbon balances are estimated. Economic analyses are carried out for carbon prices of \$0 and \$100 per tonne of carbon. Both levelized costs and internal rates of return on equity are estimated with CO_2 vented, and with CO_2 captured and stored in saline aquifers, and with CO_2 captured and used for enhanced oil recovery. Comparisons are made with coal integrated gasifier combined cycle power plants. When the carbon price is \$100 per tonne of carbon, the co-processing option is the most economically attractive option for making Fischer-Tropsch liquids. Even at zero carbon price enhanced oil recovery applications of captured CO_2 will often be economically attractive where such opportunities exist. Enhanced oil recovery is a sufficiently large and economically interesting niche in the USA (and perhaps elsewhere) that it could enable wide near-term experience with gasification-based energy and carbon capture and storage technologies.

Keywords: coal, biomass, Fischer-Tropsch, gasification, CO_2, EOR

Introduction

Carbon management options are investigated for Fischer-Tropsch (F-T) liquids—synthetic fuels that have attracted interest in light of high oil prices and oil supply security concerns.

The system configurations investigated are "polygeneration" units that use commercial "once-through" liquid-phase reactors with iron-based catalyst for synthesis of F-T fuels from syngas. The syngas unconverted in a single pass is used to make co-product electricity in a combined cycle power plant. Liquid-phase synthesis reactors and once-through synthesis configurations are well-suited for use with CO-rich syngas—such as that derived from coal via gasification.

Three carbon management options for systems using only coal are considered: one that vents the CO_2 coproduct (C-FT-V); one (Figure 1a) that captures CO_2 and stores it underground (C-FT-C); and one that involves co-capture and underground co-storage of CO_2 and H_2S (C-FT-CoC). In a fourth option (Figure 1b) coal and biomass are co-processed with co-capture and under-ground co-storage of CO_2 and H_2S (C/B-FT-CoC). For the co-processing option H_2 from biomass supplements H_2-deficient coal syngas in

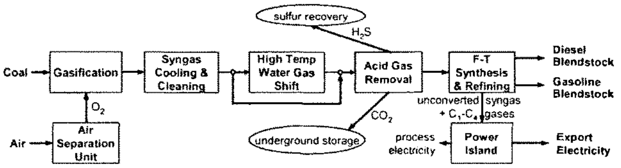

Figure 1a: Process configuration for C-FT-C energy system.

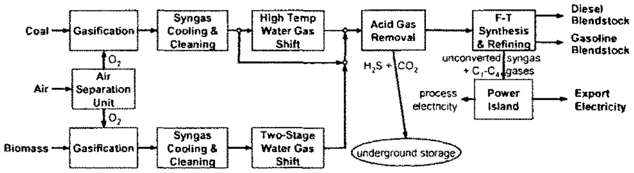

Figure 1b: Process configuration for C/B-FT-CoC energy system.

making F-T liquids, exploiting the negative emissions potential of CO_2 capture and storage (CCS) for biomass [1].

The biomass calculations are for switchgrass, which was also investigated in a companion bioenergy study [1]. Results for crop residues (an early market opportunity for biomass) are likely to be similar to the findings presented for switchgrass.

Energy and carbon balances are estimated. The economic analyses include calculations of both levelized costs and internal rates of return on equity. In the economic analyses aquifer storage (CO_2-AqS) and enhanced oil recovery (CO_2-EOR) are considered as alternative storage options. For CO_2–EOR, comparisons are made to using CO_2 from coal integrated gasifier combined cycle (IGCC) power plants.

Methodology

F-T liquids plants were modeled using: (*i*) AspenPlus chemical process simulation software to estimate detailed mass and energy balances and (*ii*) AspenPinch software for system heat integration. A GE pressurized, O_2–blown, entrained flow, quench gasifier (commercially available) is modeled for coal. C/B-FT-CoC involves modeling a separate pressurized, O_2–blown, fluidized bed gasifier based on GTI's technology (not yet commercial) for biomass but a sharing of other process equipment between coal and biomass.

For C-FT-V, syngas from the gasifier is shifted to the extent that $H_2:CO = 2.25$ for syngas entering the synthesis reactor—the value that maximizes conversion to liquid fuel. For CCS cases, $H_2:CO = 2.75$—a value at which essentially all carbon (except in CH_4) entering the synthesis reactor leaves as F-T products, and syngas conversion to liquids is only slightly below the maximum value.

After shifting the syngas, CO_2 and H_2S are captured using Rectisol technology. The CO_2 is dried and compressed or the $CO_2 + H_2S$ are dried and compressed to 150 bar and transported 100 km to a site for storage in a saline aquifer 2 km underground or in conjunction with CO_2-EOR.

The products of F-T synthesis (light gases, naphtha, middle distillates, and waxes) are sent to an integrated refinery area, the final liquid products from which are gasoline and diesel blendstocks; the light (C_1-C_4) gaseous byproducts of refining plus the unconverted syngas exiting the synthesis reactor are burned for power generation in a combined cycle plant.

For simulated energy and mass balances, installed capital costs were estimated for the four F-T plant configurations, assuming commercially-ready components for coal and future mature N^{th} plant technology components for biomass. Capital costs were developed by sub-unit in each major plant area using a database developed from prior work [1,2,3,4], literature studies, and discussions with industry experts.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. All costs are in 2003\$. It is assumed that prices for coal and biomass (20% moisture content) are $\$1.35/GJ_{HHV}$ and $\$3.0/GJ_{HHV}$ (which is likely to be typical for many residue and dedicated energy crop applications), respectively. Energy system costs are estimated for greenhouse gas (GHG) emissions having monetary values of \$0 and \$100 per tonne of carbon equivalent (tC_{equiv}).

In systems producing both F-T liquids and electricity, allocation of GHG emissions[1] and costs between the products is arbitrary. For the present analysis it is assumed that the GHG emission rate assigned to electricity (gC_{equiv}/kWh) is that for a stand-alone coal IGCC plant with CO_2 vented (C-IGCC-V) in the C-FT-V case and for a coal IGCC plant with CO_2 captured (C-IGCC-C) in all capture cases. In estimating F-T liquids production costs at a given monetary value for GHG emissions, it is assumed that the value of the co-product electricity (\$/kWh) equals the generation cost for the least-costly stand-alone C-IGCC power plant for that monetary value of GHG emissions.

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[1] The GHG emissions include CO_2 emissions from the plant and ultimate combustion of the F-T liquids and the CO_2-equivalent GHG emissions upstream of the conversion plant. From the GREET model of the Argonne National Laboratory these are estimated as 1.00 kgC_{equiv} and 2.06 kgC_{equiv} per GJ for coal and switchgrass, respectively.

Table 1: F-T liquids production with CO_2 vented or aquifer storage of CO_2 (Base Case financing)

Conversion Option	**C-FT-V**		**C-FT-C**		**C-FT-CoC**		**C/B-FT-CoC**	
Carbon flows (power balances)								
Coal input, kgC/s (MW)	74.2 (2946)		77.7 (3085)		77.7 (3085)		56.4 (2241)	
Switchgrass input, kgC/s (MW)							24.7 (886.8)	
F-T liquids output, kgC/s (MW)	21.1 (1035)		21.0 (1032)		21.0 (1033)		20.9 (1032)	
Electric power output (MW)	(461.3)		(429.9)		(428.3)		(459.5)	
Unconverted coal char, kgC/s	0.74		0.78		0.78		0.56	
Coal CO_2 emissions from plant, kgC/s	52.5		8.27		6.94		6.64	
Coal CO_2 captured & stored, kgC/s [CO_2 capture rate for coal (CCR_C), t CO_2 /GJ_{FTL}]			47.6 [0.169]		49.0 [0.174]		28.3 [0.101]	
Switchgrass CO_2 captured and stored, kgC/s [CO_2 capture rate for switchgrass (CCR_S), t CO_2/GJ_{FTL}]							22.3 [0.0791]	
Fuel cycle GHG emissions, kgC_{equiv}/GJ_{LHV} F-T liquids (relative to crude oil-derived hydrocarbon fuels)	46.73 (1.80)		27.98 (1.08)		26.68 (1.03)		5.53 (0.21)	
Fuel cycle GHG emission rate, gC_{equiv}/kWh electricity	219.4		28.8		28.8		28.8	
Price of GHG emissions, \$/tC_{equiv}	0	100	0	100	0	100	0	100
Electricity co-product value, ¢/kWh	4.75	6.94	4.75	6.94	4.75	6.94	4.75	6.94
Overnight construction cost, \$$10^6$	1647		1797		1639		1678	
CO_2 transport/storage cost, \$/t CO_2			6.59		6.47		6.50	
F-T Liquids Production Cost, \$/GJ_{LHV}								
Capital	10.63		11.63		10.60		10.87	
Operation and maintenance	2.52		2.76		2.52		2.58	
Coal input	4.01		4.21		4.20		3.06	
Switchgrass input							2.86	
Electricity co-product credit	-5.88	-8.59	-5.49	-8.03	-5.47	-7.99	-5.87	-8.58
CO_2 transport/storage cost (CTSC)			1.11		1.12		1.17	
GHG emissions cost	-	7.38	-	3.14	-	3.00	-	3.07
Credit for bio-CO_2 storage								-2.16
Net production cost, \$/GJ_{LHV} (NPC = NPC_V for venting and NPC_C for capture)	11.28	15.96	14.22	14.82	12.97	13.46	14.65	12.85
F-T liquids prod cost, \$/liter gasoline equivalent (ge)	0.355	0.502	0.447	0.466	0.408	0.423	0.461	0.404
Breakeven crude oil price, \$/barrel	50.4	61.7	66.2	55.6	59.6	48.2	68.6	44.9
Plant-gate CO_2 cost = (NPC_C - CTSC - NPC_V)/(CCR_C + CCR_S), \$/t CO_2			10.7	-13.3	3.3	-20.9	12.3	-23.8

Cost estimates are for plants with an 80% capacity factor, financing with 55% debt (4.4%/y real cost) and 45% equity, a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and an owner's cost of 5.5% of the total installed capital cost. Base Case financing involves a 14.0% real rate of return on equity (ROE), so that the discount rate (real weighted after-tax cost of capital) is 7.8%/year, and the levelized annual capital charge rate is 15.0%/year. Plant construction requires four years, with the capital investment committed in four equal payments, so that interest during construction is 12.3% of the overnight construction cost.

Costs for CO_2 transport and for aquifer storage are based on a model developed by Ogden [5], assuming that the maximum CO_2 injection rate per well for the AqS-CO_2 storage cases is 1000 t/day, a typical value for mid-continental aquifers.

Breakeven crude oil prices are estimated assuming that the F-T gasoline and diesel products (38% and 62% of liquids output, respectively) compete with gasoline and low-sulfur diesel derived from crude oil. The refining cost increment for this mix is \$10.4 per barrel.

For the CO_2-EOR cases, captured CO_2 is transported 100 km and sold for EOR at a price in \$ per 10^3 scf (1 tonne = 19 x 10^3 scf) equal to 3% of the oil price in \$/barrel—a "rule of thumb" for Permian Basin CO_2-EOR (Vello Kuuskraa, ARI, private communication, December 2005).

With Base Case financing, the economic analysis identifies the crude oil price at which F-T liquids are competitive with gasoline and diesel. Electricity costs for coal IGCC power with CO_2–EOR are also estimated with Base Case financing. The economic analysis is extended beyond Base Case financing to estimate the ROE as a function of oil price—assuming all financial parameters other than the ROE are the same as with Base Case financing.

Findings

Table 1 summarizes energy and carbon balances and the economic analysis with Base Case financing for systems with venting and aquifer storage of CO_2. With CO_2 vented, the GHG emission rate is 1.8 times that for crude-derived hydrocarbon (HC) fuels displaced, but for coal with CCS the rate is about the same as for these HC fuels, and for C/B-FT-CoC the rate is only 0.2 times that for displaced HC fuels.

Notably, only 0.86 GJ of biomass is needed to make 1 GJ of F-T liquids via C/B-FT-CoC. This is far less than the biomass required to make conventional liquid biofuels[2] and thus offers an attractive way to use scarce biomass resources to make liquid fuels with near-zero net GHG emissions.

At $0/tC the C-FT-V option competes at $50 a barrel crude oil, but the CCS options require a much higher oil price to be economically interesting. However, at $100/tC [the GHG emissions price at which C-IGCC-C (CO_2-AqS) becomes competitive with C-IGCC-V—see Table 3], the C/B-FT-CoC option would compete at a $45/barrel oil price and provide F-T liquids at a plant-gate cost of $0.40/liter ($1.5/gallon) of gasoline equivalent (ge).

Plant-gate costs of CO_2 are low—$3-$12/t (Table 1), lower than for C-IGCC-C plants (see Table 3)—suggesting that F-T liquids plants might be attractive sources of CO_2 for EOR projects. Table 2 presents an economic analysis for F-T plants coupled to CO_2-EOR with Base Case financing, showing that breakeven crude oil prices are in the range $37-$42/barrel for $0/tC (much lower than for C-FT-V, Table 1). Similarly, Table 3 shows that C-IGCC-C supporting CO_2-EOR could provide less costly electricity than C-IGCC-V at $0/tC.

Projects coupling gasification energy and CO_2-EOR could help establish CCS technologies in the market even at a carbon price of $0/tC. Recent studies [8] estimated for 10 US basins/regions the economic (technical) CO_2-EOR potential based on state-of-the-art technology to be 47 (89) billion barrels. The economic potential could support 4.3 million barrels/day of crude oil production for 30 years (a typical lifetime for a gasification energy plant that might provide the needed CO_2). At the average CO_2 purchase rate of 0.21 t CO_2/barrel estimated in these studies, the required CO_2 could in principle be provided by 60 C-FT-C plants (Table 2) or 126 C-IGCC-C plants (Table 3). Although coupling gasification energy and CO_2–EOR projects will not always be feasible, this "niche activity" would nevertheless be large enough to gain extensive early experience and technology cost buydown (learning by doing) for both gasification energy and CCS technologies.

Figures 2a and 2b show the ROE as a function of oil price at $0/tC and $100/tC, respectively. At $0/tC, the CO_2-EOR-supporting options would almost always be more profitable than C-FT-V; C-IGCC-C supporting CO_2-EOR is the most profitable option at low oil prices but FT-C options supporting CO_2-EOR are more profitable at high oil prices. At $100/tC, C-IGCC-C with CO_2-EOR is the most profitable option, and C/B-FT-C (characterized by near-zero GHG emission rates for both F-T liquids and electricity) is more profitable than any C-FT option at all oil prices and for both storage options (CO_2-EOR and CO_2-AqS).

Conclusions

Making F-T liquids from coal could help mitigate oil supply security concerns and would be profitable at sustained high oil prices. But without CCS, this option would lead to a large increase in GHG emissions relative to hydrocarbon fuels derived from crude oil.

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[2] For comparison, the net biomass required to make 1 GJ of F-T liquids from switchgrass with CO_2 vented is 1.56 GJ [1], while the net biomass required to make 1 GJ of cellulosic ethanol from corn stover is 2.89 GJ with vintage 2000 technology (58.4 gallons per dry short ton) [6] and 1.77 GJ with advanced technology (89.8 gallons/ton) [7].

With CCS, the GHG emission rate for coal F-T liquids could be reduced to about the rate for crude oil-derived fuels. The net GHG emission rate could be reduced further, to near zero, via co-processing biomass and coal with CCS so as to exploit the negative emissions of storing photosynthetic CO_2. At a carbon price of $100/tC the co-processing option is the most economically attractive of all the options considered for F-T liquids production and requires far less net biomass input to realize near zero GHG emissions than conventional biofuels such as cellulosic ethanol.

If the CO_2 captured in F-T or IGCC plants were used for CO_2-EOR, the economics of CO_2 capture and storage would often be attractive even at a carbon price of $0/tC. CO_2-EOR opportunities in the USA (and perhaps elsewhere) are sufficiently large to make the CO_2-EOR application an attractive way to gain extensive near-term experience with gasification-based energy and CCS technologies and the opportunity to "buy down" the costs of these technologies substantially as a result of learning by doing.

Table 2: Economics of F-T liquids production if CO_2 is used for EOR (Base Case financing)

Conversion Option	**C-FT-C**		**C-FT-CoC**		**C/B-FT-CoC**	
CO_2 available for EOR, t CO_2/hour	628.4		646.0		667.5	
Barrels of crude EOR/barrel of F-T liquids (ge)	4.00		4.11		4.25	
Price of GHG emissions, $/$tC_{equiv}$	0	100	0	100	0	100
Electricity co-product value, ¢/kWh	4.75	6.94	4.75	6.94	4.75	6.94
Price at which CO_2 is sold for EOR, $/t CO_2	23.6	19.6	20.9	16.5	23.9	15.2
CO_2 transport cost (100 km), $/t CO_2	2.94		2.89		2.84	
F-T Liquids Production Cost, $/$GJ_{LHV}$						
Capital	11.63		10.60		10.87	
Operation and maintenance	2.76		2.52		2.58	
Coal input	4.21		4.20		3.06	
Biomass input					2.86	
Electricity co-product credit	-5.49	-8.03	-5.47	-7.99	-5.87	-8.58
CO_2 transport cost	0.50		0.50		0.51	
GHG emissions cost	-	3.14	-	2.92	-	3.07
Credit for EOR	- 3.99	- 3.31	- 3.63	- 2.86	- 4.30	- 2.73
Credit for bio-CO_2 storage						-2.16
Net F-T liquids production cost, $/$GJ_{LHV}$	9.61	10.89	8.73	9.89	9.70	9.46
F-T liquids production cost, $/liter, ge	0.302	0.342	0.274	0.311	0.305	0.298
Breakeven crude oil price, $/barrel	41.4	34.4	36.6	28.9	41.9	26.7

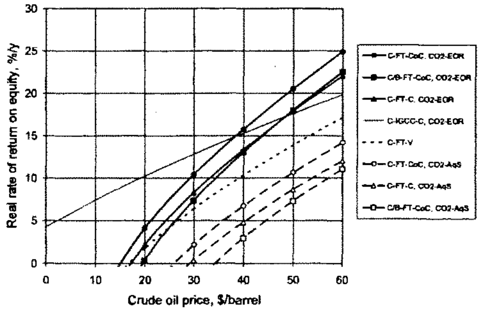

Figure 2a: ROE vs. oil price @ $0/tC.

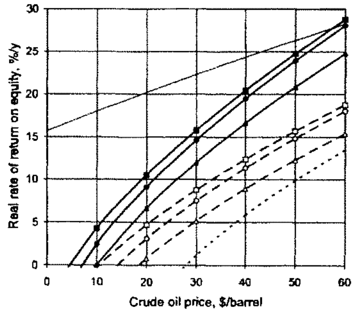

Figure 2b: ROE vs. oil price @ $100/tC.

Table 3: Performances and costs for coal IGCC power plants[a] (Base Case financing)

Conversion Option	C-IGCC-V		C-IGCC-C			
Storage mode			CO_2-AqS		CO_2-EOR	
Price of GHG emissions, \$/tC$_{equiv}$	0	100	0	100	0	100
Installed capacity, MW$_e$	390.1		361.9			
CO_2 storage rate, t CO_2/hour			297.3			
Barrels of crude EOR per day/GW$_e$ of C-IGCC-C capacity			74,700			
CO_2 emission rate from plant, t CO_2/hour	301.5		25.2			
Fuel cycle GHG emission rate, gC$_{equiv}$/kWh	219.4		28.8			
Efficiency at design point, LHV	42.95		36.79			
CO_2 transport cost, \$/t CO_2			4.33			
CO_2 storage cost, \$/t CO_2			3.84		-	
Price at which CO_2 is sold for EOR, \$/t CO_2—assumed to be the same as for the C-FT-C option in Table 2 (assumed crude oil price, \$/barrel)					23.6 (41.4)	19.6 (34.4)
Overnight construction cost (OCC), \$/kW$_e$	1187		1531			
Generation Cost, ¢/kWh						
Capital	2.85		3.68			
Operation and maintenance	0.68		0.87			
Fuel	1.22		1.42			
CO_2 transport			0.36			
CO_2 storage			0.31		-	
Credit for EOR					- 1.94	- 1.61
GHG emissions	0	2.19	0	0.29	0	0.29
Total	4.75	6.94	6.64	6.93	4.39	5.01
Plant-gate CO_2 cost, \$/t CO_2			14.8	- 8.3		

[a] Based on [4] except that (as for the F-T polygeneration analysis) the coal is assumed to have a heating value of 23.5 GJ$_{LHV}$/tonne and a C content of 25.2 kgC/GJ$_{LHV}$.

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Making it up as you go along

Chemists can make liquid fuel from biomass — or from coal. **Heidi Ledford** weighs up the pros and cons.

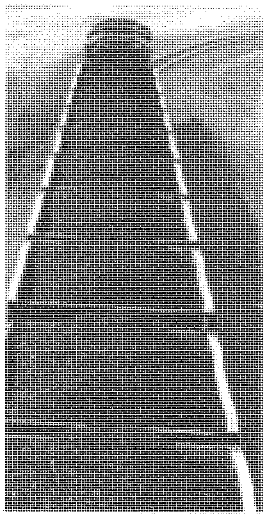
Brian Schweitzer, a rancher and the Democratic governor of Montana, has 'folksy' down to a fine art. In a bolo tie, jeans and cowboy boots, Schweitzer shifts seamlessly from jokes about how his border collie, Jag, drinks out of the toilet to analyses of energy policy in which every complex problem gets its down-to-earth soundbite, from pumping carbon dioxide into the ground ("It came from those rocks, we're just sending it home") to public perceptions of coal as a dirty source of energy ("To a lot of people, coal is a four-letter word").

Put these aperçus all together and you have a pitch for turning coal into oil, an idea Schweitzer and his constituents have 240 billion reasons to take seriously. With 8% of the world's reserves, Montana has enough coal to make 240 billion barrels of diesel fuel, which is in the same ball park as all of the proven reserves claimed by Saudi Arabia.

Schweitzer is far from alone; many politicians and businessmen are now eyeing a chemical process called the Fischer–Tropsch synthesis as a way of converting solid hydrocarbons or natural gas into liquid fuel. The great advantage is energy security: Fischer–Tropsch technology allows domestic coal to replace foreign oil, which is pretty attractive if you're sitting in Washington DC or Beijing, let alone Billings, Butte or Bozeman. Another potential advantage is environmental: the fuel produced by Fischer–Tropsch methods can be made to burn more cleanly than diesel. It could thus ease the adaption of cars with efficient diesel engines in countries, such as the United States, that have so far been resistant to such technology.

The obvious drawback, though, is also environmental. The process of converting coal into liquid and using it for transportation releases nearly twice as much carbon dioxide as burning diesel made from crude oil does. In a world conscious of climate change, that excess carbon is a problem. "If you make liquids from coal and don't capture carbon dioxide in the process, you're effectively doubling emissions," says Eric Larson, a research engineer at Princeton University's Environmental Institute in New Jersey.

One way round this problem might be to take the carbon dioxide and bury it underground. Another would be to replace fossil-fuel feedstock with biomass. That is in some ways an attractive option — but it is also, as yet, an immature technology.



Around the bend: is there a feasible future for liquid fuels made from coal?

W. CAMPBELL/CORBIS

Expense is another issue. To date, Fischer–Tropsch has always been rather costly, and thus something people normally start to do only when they have no alternatives. Its first major use was during the Second World War, when the blockaded Nazis produced about 90% of their diesel and aviation fuel with the technologies originally developed by Franz Fischer and Hans Tropsch at the Kaiser Wilhelm Institute for Coal Research in 1923. South Africa began liquefying coal in response to apartheid-era sanctions, and in part as a result of its investment back then, continues to derive about 30% of its fuel from liquefied coal.

To make liquid fuel from coal, you first shatter the long hydrocarbon chains into a mixture of hydrogen and carbon monoxide using high temperatures and intense pressure. This is also the first step for the "integrated gasification combined cycle" plants, seen by many as the future of coal-fired generation — a technology that has many synergies with coal-to-liquids. In Fischer–Tropsch synthesis, the gas is not burned but channelled to a reactor where catalysts reunite the carbon and hydrogen to form hydrocarbon chains of varying lengths, including diesel and petrol. During both phases — gasification and liquefaction — some carbon is given off as carbon dioxide.

Because contaminants such as mercury and sulphur can inhibit the reaction, companies have a built-in incentive to remove impurities from the gas before liquefying it. And the choice of catalyst allows the make-up of synthetic fuel to be tailored to an extent. As a result, diesel produced by the Fischer–Tropsch process is quality stuff. It contains less sulphur and fewer contaminating aromatic compounds, such as benzene and toluene, and releases fewer particulates when burnt than regular diesel fuel does.

Capturing carbon

But none of that solves the carbon dioxide problem. In the United States, all coal-to-liquid plants on the drawing board would include carbon capture followed by, in most cases, sequestration, says Lowell Miller, director of the US Department of Energy Office of Sequestration, Hydrogen, and Clean Coal Fuels. That includes the 22,000-barrel-a-day operation near the town of Roundup that Schweitzer has proposed. But the Natural Resources Defense Council (NRDC), a US-based environmental group, says that even if 90% of that carbon were captured, producing and using coal-derived fuels would still release 8% more carbon dioxide than petroleum-derived fuels[1]. "Even if you do carbon sequestration, at best coal-to-liquid methods are still no better than crude oil in terms of lifecycle emissions," says David Hawkins, director of the NRDC's Climate Center. "And if we are building a new industry to make transportation fuels, we need to build an industry that produces fuels that are significantly lower in carbon dioxide emissions."

In China — which, like the United States, is not bound by the Kyoto Protocol, and which has vast coal reserves — carbon sequestration is less likely. Yong-Wang Li, director of Synfuels China in Shanxi, says that there are two proposed coal-to-liquid industrial plants under consideration in China and that, at present, neither proposal contains plans for sequestering carbon.

The advantage of using plant biomass as a feedstock from which to make synthetic fuel, on the other hand, is that no sequestration is necessary — the emitted carbon is carbon that came

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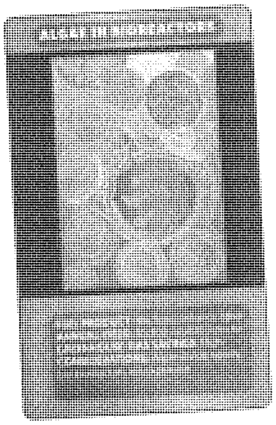


from the air in the first place. If one were to add sequestration to a biomass-to-liquids plant, the result could be 'carbon negative', in that the net effect on the atmosphere would be to draw down the level of carbon dioxide as some of the carbon dioxide fixed by the plant would be sequestered into the planet's crust. What's more, Fischer–Tropsch methods could complement, at the very least, some other biomass technologies.

Plant material that contains too much lignin and not enough cellulose for use in cellulosic ethanol projects (see page 673) could still be used in a Fischer–Tropsch system. The technique could open up the possibility of using forest thinnings and other sources of wood waste, or even the lignin-rich residue left over from cellulosic ethanol production, says David Dayton, a senior scientist at the National Renewable Energy Laboratory in Golden, Colorado. Others think that Fischer–Tropsch could outcompete the fermentation of cellulose more generally.

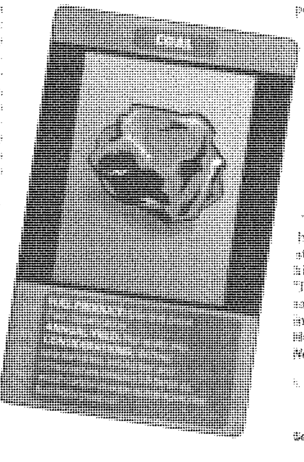
But the technology for gasifying biomass currently lags well behind the development of such methods for coal. The Netherlands has invested a lot of research into the process, but still operates only demonstration-scale biomass-only plants. Choren, a German company, and Shell are building a commercial plant in Freiberg, which will produce 15,000 tonnes per year (110,000 barrels per year) of what Choren calls SunDiesel. Construction of five 200,000-tonnes-per-year facilities that will use wood and agricultural waste is scheduled to begin in 2008. By far the biggest undertaking of its kind to date, the total output from this project would still be enough to supply only about 4% of Germany's projected diesel needs in 2015.

R. HODGKINS

The other big issue is cost. Several US demonstration coal-to-liquid plants, established during the spike in oil prices during the 1970s, closed without leading to further commercial development after oil prices fell in the early 1980s. Miller and Jim Bartis, a policy analyst at the RAND corporation in Santa Monica, California, both think that oil prices must be above \$50–\$55 a barrel (159 litres) for coal-to-liquid plants to make long-term economic sense. With oil prices currently just under \$60 a barrel that's already an uncomfortably snug fit – and there's no guarantee of prices staying at that level.

Biomass boost

Nevertheless Chevron, Shell and Exxon have all invested in development of Fischer–Tropsch technologies, as has the biggest US coal company, Peabody Coal, which is working on Schweizer's Roundup plant with Rentech of Denver, Colorado. "Some of the big players are willing to take a low rate of return just to establish a technology position," says Bartis. "Once you build a first plant, you're going to learn by doing, and subsequent plants are going to cost less." Another strategy is to concentrate on people who might pay a premium for domestic hydrocarbons. Syntroleum of Tulsa, Oklahoma, recently provided samples of its natural-gas-derived jet fuel, made with technology licensed from Exxon Mobil, to the US Air Force for testing.



For biomass, the situation is worse. Robin Zwart of the Dutch Energy Research Centre in Petten hopes that upcoming improvements in efficiency will drive the price down, but says that oil prices will still have to exceed \$70–80 per barrel to make liquid fuels from, for example, willow trees economical. That said, carbon taxation or emissions trading would give a boost to biomass-based systems that are unavailable to coal-to-liquid systems.

That is why, until biomass supply and technology are scaled up, there is still the appealing option of spiking coal feedstock with biomass. Coupled with carbon sequestration, this would reduce greenhouse gas emissions without requiring much change to existing technology, says Robert Williams, a researcher at Princeton University's Environmental Institute. Williams has calculated that a mixture of 89% coal and 11% biomass could reduce carbon emissions by 19% relative to using the same process with coal only.

Because they can't yet make money, current Fischer–Tropsch projects often involve a complex mix of industry partners and government subsidies. Sasol of South Africa, a veteran in the easier gas-to-liquids game, considers government subsidies crucial. Sasol is conducting feasibility studies for coal-to-liquid projects in China and India, and has partnered with oil giant Chevron in Europe. But it is waiting to see what develops with government subsidies, according to chief executive Pat Davies, before committing to any US projects.

So far, the US federal government has proposed tax credits for coal-to-liquid programmes, and provides grants to interested companies. States are also pitching in: Pennsylvania, for example, is guaranteeing \$465 million in loans and \$47 million in tax credits for a proposed plant in Schuylkill County. Elsewhere in the world — in China, India and the Philippines, for example — liquefaction projects have received pledges of strong government support. And in Germany, biomass-derived fuels are exempt from the heavy taxes levied on other fuels.

Miller says he is optimistic that Fischer–Tropsch fuels could finally establish a foothold in the United States. But 30 years of studying coal-to-liquid technology has taught him to temper his enthusiasm with caution. "I've been in this business for a long time," he says, "and I'll believe it when the shovel goes into the ground." ■

Heidi Ledford is a science writer currently in *Nature*'s Washington DC office.

1. Williams, R. H., Larson, E. D. & Jin, H. 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, 19-22 June 2006.

See Editorial, page 654.

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Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels

Prepared for

U.S. Department of Energy
National Energy Technology Laboratory

Prepared by

Energy and Environmental Solutions, LLC

John J. Marano
Jared P. Ciferno

June 2001

The U.S. Department of Energy's National Energy Technology Laboratory study entitled

> "Life-Cycle Greenhouse-Gas Emissions Inventory For Fischer-Tropsch Fuels" (June 2001)
> *by John J. Marano and Jared P. Ciferno*,

may be obtained from the technical reports inventory on the NETL's website.

http://www.netl.doe.gov/publications/others/techrpts/techrpts_toc.html.

Well-to-Wheel Analysis of Greenhouse Gas Emissions of Automotive Fuels in the Japanese Context

- Well-to-Tank Report -

November, 2004

TOYOTA MOTOR CORPORATION

Mizuho Information & Research Institute, Inc.

This report is available as an ADOBE pdf file on the MHIR website at http://www.mizuho-ir.co.jp/english/

Questions and remarks may be sent to kankyo@mizuho-ir.co.jp

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Preface

According to the diversification of automotive fuels and powertrain technologies, advanced technology vehicles such as hybrid electric vehicles with gasoline and diesel, and various fuel cell based vehicles, have been under research and development extensively. Against this background, in order to evaluate the greenhouse gas emission reduction potentials, we focuses on estimating Well-to-Tank (= consideration of the fuel from resource recovery to delivery to the vehicle tank) greenhouse gas emissions of automotive fuels to be used in Japan for present and near future. Further, by adding these well-to-tank results, we show Well-to-Wheel (=integration of the well-to-tank and tank-to-wheel components) greenhouse gas emissions under the specific condition of driving a sedan.

We hope that these data of this study will be useful for those who are planning to conduct fuel-cycle analysis in the future.

Study Organization

This study was carried out the project team that was organized by environment-related organizations in Mizuho Information & Research Institute, Inc. In addition, in order to ensure Well-to-Tank data impartiality, efforts were made to improve credibility by seeking varied advice, ranging from third party evaluations by specialists (Advisory Committee) up to obtaining calculation methods from the data sources.

The participants of this project were as follows:

<Advisory Committee>

(Chairman)	Hisashi ISHITANI	Graduate School of Media and Governance, Keio University
	Masaki IKEMATSU	General Manager, Fuel Cell Testing Dept., Nippon Oil Corporation
	Fumihiro NISHIMURA	General Manager, Siting & Environment, The Federation of Electric Power Companies
	(Takao KITAHARA	Deputy General Manager, Siting & Environment, The Federation of Electric Power Companies)
	Kiyokazu MATSUMOTO	General Manager, Environment Dept., The Japan Gas Association
	Kiyoshi NAKANISHI	Senior Director of Research, Genesis Research Institute, Inc. (Advisor, Toyota Motor Corporation)
	Shigeki KOBAYASHI	IPCC Coordinating Lead Author (Senior Researcher, Strategic Planning Office, Toyota Central R&D Labs., Inc.)

<Toyota Motor Corporation>

(Representative)	Hirohiko HOSHI	Senior Staff Engineer, Fuel & Lubricant Department

<Mizuho Information & Research Institute, Inc.>

(Representative)	Yasushi KAJI	Senior Research Associate, Environmental Strategy

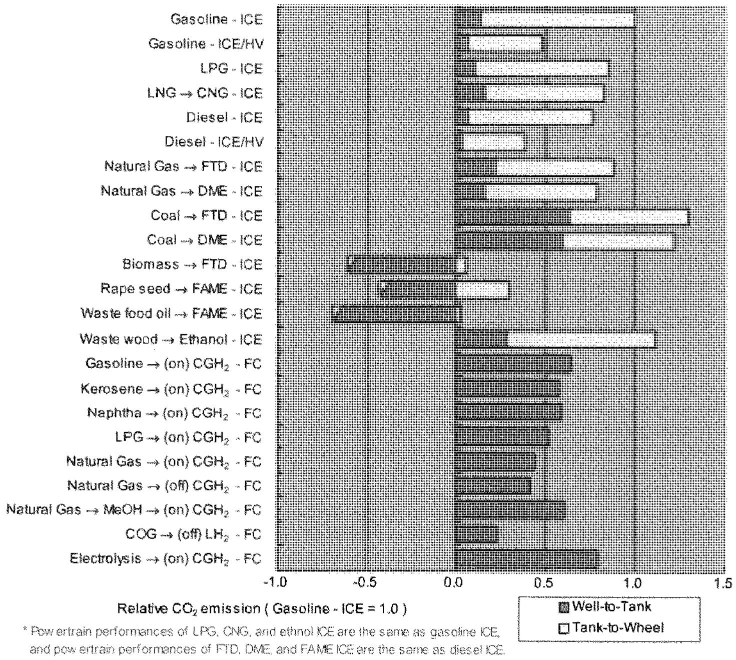
Acknowledgments

We would like to thank members of Advisory Committee and specialists at the various institutions that supported our study during the process of hearing and editing this report.

Executive Summary

With the impending practical application of fuel cell vehicles (FCV), the choice of propulsion systems, along with gasoline and hybrid vehicles is increasing, while on the other hand, the diversification of fuels is also progressing. From this background, Toyota Motor Corporation (TMC) commissioned Mizuho Information & Research Institute, Inc. (MHIR) to conduct this study with the objective of establishing a foundational understanding needed to consider the potential of various technologies and automotive fuels in the reduction of environmental load.

The calculations of this study mainly concern Well-to-Tank (=consideration of the fuel from extraction of primary energy to vehicle fuel tank) energy consumption, greenhouse gas (GHG) emissions and energy efficiency of current and near future automotive fuels in Japan. The results of this study were subsequently combined with data related to Tank-to-Wheel (=assessing vehicle architecture, powertrain and fuel effects) studies previously conducted by TMC, and a case study showing Well-to-Wheel (=integration of the Well-to-Tank and Tank-to-Wheel components) GHG emissions under fixed conditions of driving sedan type vehicles, was calculated (See figure below).



* Powertrain performances of LPG, CNG, and ethnol ICE are the same as gasoline ICE, and powertrain performances of FTD, DME, and FAME ICE are the same as diesel ICE.

(See page 104 "3.2 Case study: Tank-to-Wheel and Well-to-Wheel GHG emissions" for more details on preconditions of the calculation.)

Figure Well-to-Wheel GHG emissions under fixed conditions of driving sedan type vehicles

Regarding Well-to-Tank studies, the fuel production pathways considered were; 21 petroleum based fuels, 20 natural gas based fuels, 8 coal based fuels, 19 biomass resource related fuels (3 bio-diesel fuels, 10 dry biomass based fuels, 6 wet biomass based fuels), power grid mix (Japan average) and hydrogen production through electrolysis, 6 byproduct hydrogen pathways, totaling 76 pathways. No fixed timeframe was set for the data collected, with efforts focusing on understanding and organizing existing data. Additionally, in order to ensure data impartiality, efforts were made to improve credibility by seeking varied advice, ranging from third party evaluations by specialists (Advisory Committee) up to obtaining calculation methods from the data sources. Moreover, where data used in calculation has a broad range, the range is indicated through minimum to maximum values.

Furthermore, for Well-to-Wheel, in concurrence with previous research for the "10-15 mode run" (example of calculations made in this study), which is mainly a comparatively low-speed run, significantly superior results were obtained for hybrid electric vehicles (gasoline, diesel) in relation to GHG emissions. For synthetic fuels such as Fischer-Tropsch Diesel Oil and Dimethyl Ether (DME), and hydrogen, large variations in Well-to-Tank GHG emissions were apparent depending on the primary energy used as feedstock, and it is clear that an important aspect of future considerations will be the production of fuels through low GHG emission pathways. Moreover, regarding hydrogen, during transition, hydrogen derived from fossil fuels such as natural gas has also shown results similar to that of hybrid electric vehicles, and depending on trends in CO_2 capture and storage, possibilities of further reductions in GHG emissions with these pathways are conceivable. In addition, fuels derived from biomass resources have comparatively low GHG emission values, and future utilization is anticipated.

The credibility and applicability of calculations in this study depends greatly on calculation preconditions such as implemented load distribution methods and quality of data. In reality, some fuels such as petroleum products, city gas, liquefied petroleum gas (LPG) and electricity are already in industrial use, while biomass resources, synthetic fuels, hydrogen, and so on, are still in the early stages of technological development. In addition, even where calculation results of this study are based on actual values, as there is a high degree of uncertainty concerning future technological innovation, market size, new laws and regulations, and such, many problems exist concerning the simple comparison of these fuels. Furthermore, regarding load distribution between main products and co-products/byproducts, although this study has been conducted under the premise that, in principle, byproducts will be disposed of, the usage of certain byproducts has been considered in prior studies although the possibility of realizing this usage is unclear (load distribution considerations). Also, regarding the sphere of the system, the environmental load from the production process of byproduct hydrogen feedstock such as coke oven gas (COG) has not been taken into consideration in this study. For these reasons, the calculation results of this study are not unlike preliminary approximations, and in order to contribute further to the initial objectives, the consistency of preconditions and the accuracy of data used in calculations must be improved, and the credibility of the results must be enhanced.

The emphasis of this study is on Well-to-Tank analysis. In future, these results will be combined with various Tank-to-Wheel analysis results and basic data, and various further analyses are scheduled in relation to overall efficiency from extraction of primary energy to actual vehicle fuel consumption "Well-to-Wheel". At such a time, it may also become necessary to modify or adjust the calculation results of this study in order to comply with analysis preconditions.

Well-to-Wheel analysis results will be an important factor in the selection of future technologies and fuels.

However, technologies and fuels that will be implemented in the future will not be determined by this factor alone. This is because a variety of other factors such as cost, infrastructure, completeness of the technology, supply potential and usability will also be taken into consideration. In future, it will be necessary to seek out optimum vehicle/fuel combinations according to the energy circumstances, available infrastructure and regulations that apply in each country or region. See page 104 "3.2 Case study: Tank-to-Wheel and Well-to-Wheel GHG emissions" for more details on preconditions of the calculation.

Table of Contents

Preface .... (1)

Executive Summary .... (3)

1. Goal and Scope in This Study 1

  1.1 Goal 1
  1.2 Scope 1
    1.2.1 Fuels and fuel production pathways 2
    1.2.2 Data categories 6
    1.2.3 Calculation procedures 7

2. Well-to-Tank Data Compilation Procedures and Calculation Methods 11

  2.1 Petroleum Based Fuel Production Pathways 11
    2.1.1 Abstract 11
    2.1.2 Procedures for data collection of unit process 13
    2.1.3 Calculation results 19
  2.2 Natural Gas Based Fuel Production Pathways 20
    2.2.1 Abstract 20
    2.2.2 Procedures for data collection of unit process 21
    2.2.3 Calculation results 27
  2.3 Fuel Production Pathways from Biomass Resources 29
    2.3.1 Abstract 29
    2.3.2 Procedures for data collection of unit process 32
    2.3.3 Calculation results 43
  2.4 Synthetic Fuel Production Pathways 46
    2.4.1 Abstract 46
    2.4.2 Procedures for data collection of unit process 51
    2.4.3 Calculation results 60
  2.5 Liquefied Petroleum Gas Production Pathways 62
    2.5.1 Abstract 62
    2.5.2 Procedures for data collection of unit process 62
    2.5.3 Calculation results 64

- 2.6 Electricity (Electric Power Generation Pathways) 65
  - 2.6.1 Abstract 65
  - 2.6.2 Procedures for data collection of unit process 68
  - 2.6.3 Calculation results 76
- 2.7 Hydrogen Production Pathways 77
  - 2.7.1 Abstract 77
  - 2.7.2 Procedures for data collection of unit process 79
  - 2.7.3 Calculation results 89

3. Results and Conclusions 98
- 3.1 Well-to-Tank Analysis Results 98
- 3.2 Case study: Tank-to-Wheel and Well-to-Wheel GHG emissions 104
  - 3.2.1 Assumptions about Tank-to-Wheel analysis 104
  - 3.2.2 Well-to-Wheel GHG emissions under fixed conditions of driving sedan type vehicles 105
- 3.3 Considerations and Future Tasks 106
  - 3.3.1 Considerations about Well-to-Tank analysis 106
  - 3.3.2 Future tasks 111

4. References 112

1. Goal and Scope in This Study

1.1 Goal

With the impending practical application of fuel cell vehicles (FCV), the choice of propulsion systems, along with gasoline and hybrid vehicles is increasing, while on the other hand, the diversification of fuels is also progressing. With this background, for the continued utilization of motor vehicles in society, it is the objective of this study to establish the foundational understanding needed to consider the potential of various technologies and fuels, concerning the reduction environmental load, without sacrificing the convenience of mobility.

Specifically, the investigation and compilation of various fuel production pathways for potential automotive fuels with future technologies are taken into consideration, with incremental calculations for Well-to-Wheel energy consumption, GHG emissions and energy efficiency for each pathway.

1.2 Scope

The lifecycle of an automobile consists of the fuel supply cycle (resource extraction to production to fuel tank), the vehicle cycle (vehicle manufacture, running, disposal/recycling) and other related infrastructure cycles (See Figure 1.1). Of these cycles, this study focuses mainly on the fuel supply cycle within Japan, with Well-to-Tank calculations for energy consumption, GHG emissions and energy efficiency.

In addition, as a separate case study, reference data was calculated for Well-to-Wheel GHG emissions relevant to the running stage of the vehicle cycle under predetermined conditions.

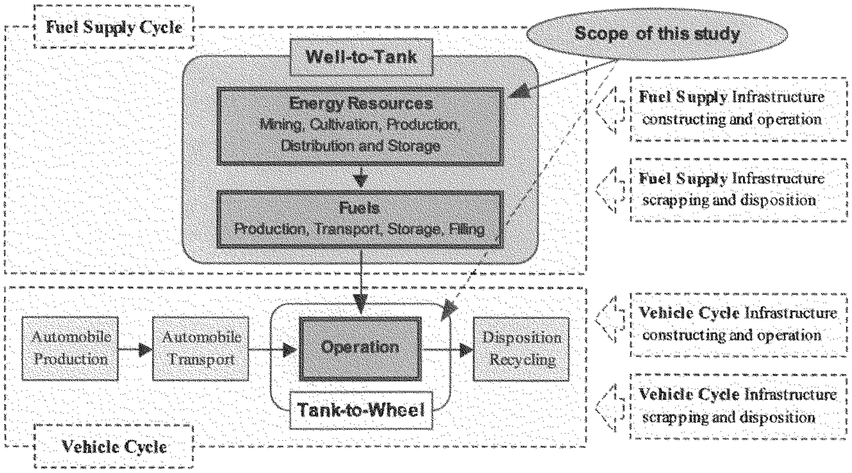

Fuel Supply Cycle
Scope of this study
Well-to-Tank
Energy Resources
Mining, Cultivation, Production, Distribution and Storage
Fuels
Production, Transport, Storage, Filling
Fuel Supply Infrastructure constructing and operation
Fuel Supply Infrastructure scrapping and disposition
Automobile Production
Automobile Transport
Operation
Disposition Recycling
Tank-to-Wheel
Vehicle Cycle Infrastructure constructing and operation
Vehicle Cycle Infrastructure scrapping and disposition
Vehicle Cycle

Figure 1.1 Scope of this study

1.2.1 Fuels and fuel production pathways

To begin with, following the compilation of fuel production pathways applicable for automotive fuels in Japan, the fuel production pathways to be considered were selected from the perspectives of (1) Already realized, (2) High probability of realization in the future, (3) Strong repercussion effect in the event of realization.

The fuel production paths considered in this study are shown in Table 1.1 ((A) Petroleum Based, (B) Natural Gas Based, (C) Coal Based, (D) Biomass Resource Related, (E) Power grid mix (Japan average), (F) Byproduct Hydrogen).

Table 1.1 (A) Fuels and fuel production paths – Petroleum Based

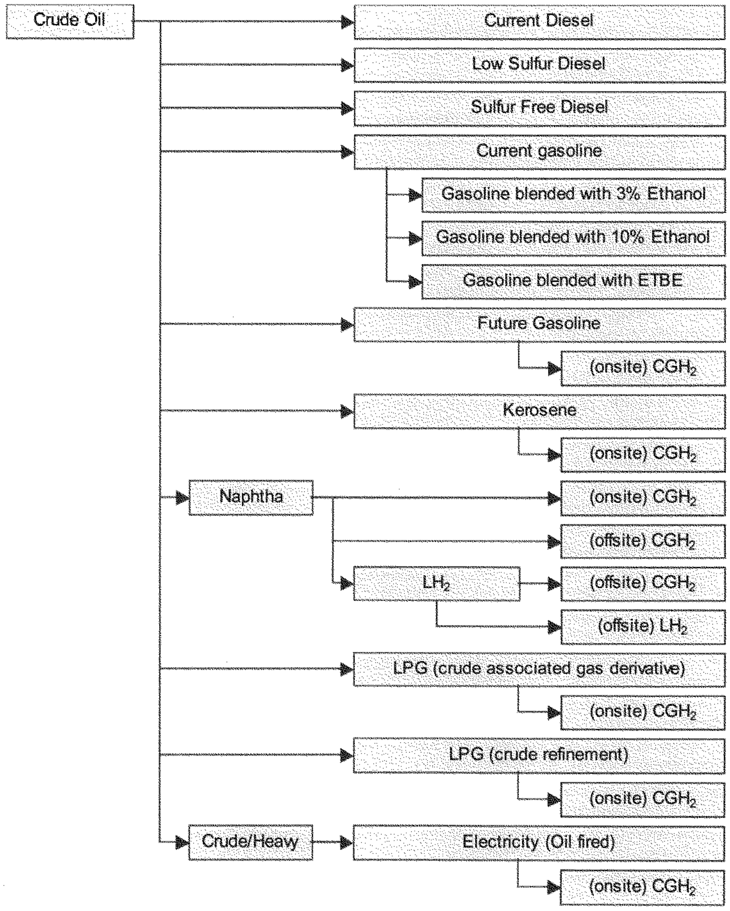


Table 1.1 (B) Fuels and fuel production paths – Natural Gas Based

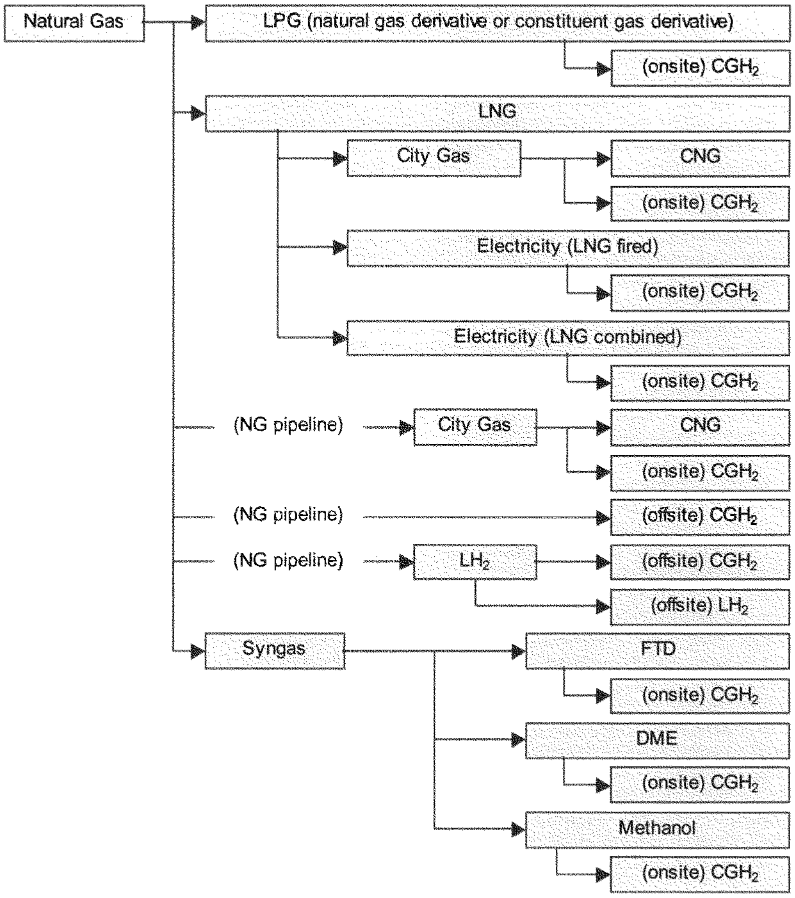


Table 1.1 (C) Fuels and fuel production paths – Coal Based

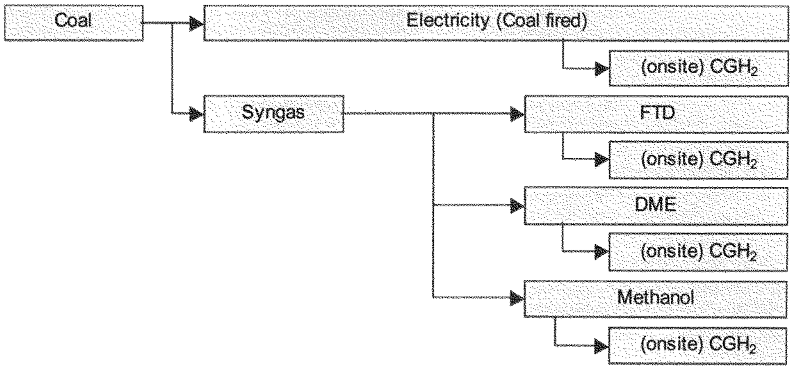


Table 1.1 (D) Fuels and fuel production paths – Biomass Resources Related

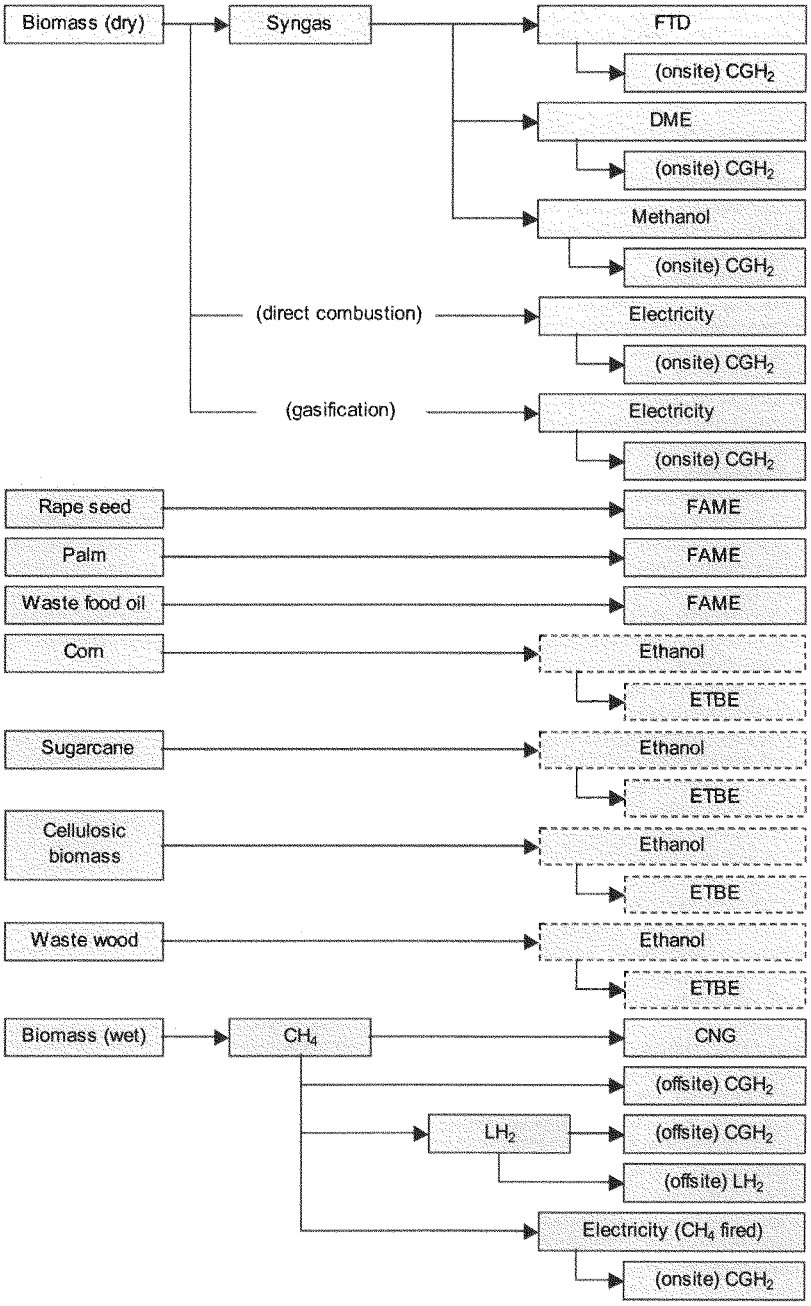


Table 1.1 (E) Fuels and fuel production paths – Power Grid Mix (Japan average)

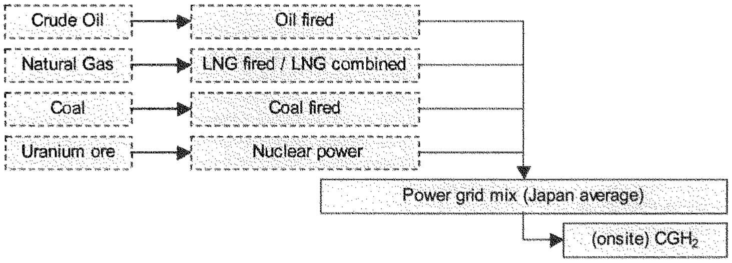
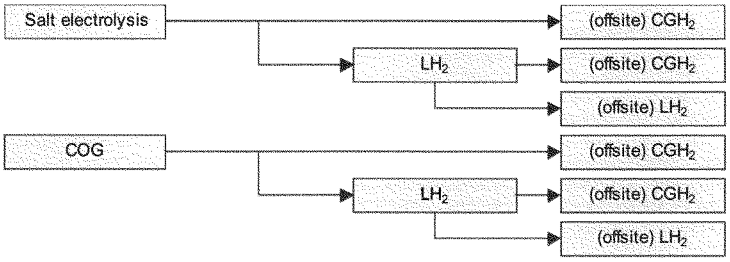


Table 1.1 (F) Fuels and fuel production paths – Byproduct Hydrogen



Furthermore, for this study, in order to conduct efficient data calculations, the processes forming the fuel production pathways shown in Table 1.1 were classified into the following groups.

(1) Petroleum Based Fuel Production Pathways → See 2.1
(2) Natural Gas Based Fuel Production Pathways → See 2.2
(3) Fuel Production Pathways from Biomass Resources → See 2.3
(4) Synthetic Fuel Production Pathways → See 2.4
(5) LPG Production Pathways → See 2.5
(6) Electricity (Electric generation pathways) → See 2.6
(7) Hydrogen Production Pathways → See 2.7

The compilation procedures and calculation methods used for each unit process data are described in "2. Well-to-Tank Data Compilation Procedures and Calculation Methods". The results of Well-to-Tank energy consumption, GHG emissions and energy efficiency calculations derived through the combination of this process data and the conclusions drawn are discussed in "3. Results and conclusions".

1.2.2 Data categories

Within this study, issues related to the following were considered as environmental load issues.

[Energy consumption]

- Energy consumption (lower heating value) [MJ]
- Energy efficiency (lower heating value) [%]

[Emission to air]

- GHG emissions: Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) [kg]

Furthermore, in light of the objectives of the study, only the above issues were considered, and emissions to air, water and land other than the above were excluded from evaluation.

Additionally, regarding calculating category indicator results within climate change, referring to Intergovernmental Panel on Climate Change (IPCC) [2001], the Global Warming Potential (GWP) 100-year factor, frequently used as an index to show the magnitude of climate change, was used as the characterization factor. The following reasons can be given regarding the use of the 100-year factor:

- The lifespan of CO_2 in the atmosphere is 120 years,
- IPCC recommends a time horizon of 100 years.

Regarding emissions other than CO_2 (CH_4, N_2O), evaluation was conducted through conversion to equivalent CO_2 in accordance with the GWP 100-year factor.

$$\text{GWP indicator result [kg eq-}CO_2\text{]} = \text{GHG emission [kg]} * \text{GWP 100-year factor [kg eq-}CO_2\text{/kg]}$$

The GWP 100-year factor used in this study is shown in Table 1.2 (IPCC [2001]).

Table 1.2 Characterization factor

GHG emission	GWP
Carbon Dioxide (CO_2)	1
Methane (CH_4)	23
Nitrous Oxide (N_2O)	296

1.2.3 Calculation procedures

This study employed the "Conventional Process-based LCA Method", studying data per process within the lifecycle from the production of each fuel up to supply to the vehicle.

Unless specifically stated otherwise, the data shown in Table 1.3 in relation to fossil fuel combustion and the use of electricity, was used to calculate energy consumption and CO_2 emissions for each process. Therefore, input/output in relation to fossil fuel combustion was converted to energy input/output by multiplying the heating values given in Table 1.3, or in relation to electricity usage, by multiplying the energy consumption values per kWh shown in Table 1.4. Subsequently, energy consumption and CO_2 emissions were calculated by multiplying the heating values and CO_2 emission factors during combustion given in Tables 1.3 and 1.4.

In this study, energy efficiency of a pathway was calculated as the simple product of the numerator, taken as the energy (heating value) of the product of each process, and the denominator, calculated as the sum of the energy (heating value) of the resources injected into the process and the energy consumed in the process.

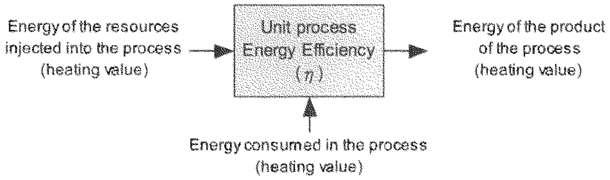

Energy of the resources injected into the process (heating value)
Unit process Energy Efficiency (η)
Energy of the product of the process (heating value)
Energy consumed in the process (heating value)

Figure 1.2 Energy efficiency of the unit process

$$\eta = \frac{\text{Energy of the product of the process (heating value)}}{\text{Energy of the resources injected into the process + Energy consumed in the process (heating value)}}$$

Regarding heating value, for general LCA purposes, higher heating value (= value which includes the condensation heat (latent heat of vaporization) of moisture in the fuel and steam generated through combustion in the heating value. HHV) is used. However, as the operating temperature of the combustion engine of this study is high and latent heat recovery for steam is difficult, it was decided that lower heating value (= value that does not include the condensation heat of steam. LHV) would be used as the basis for calculations in this study. Furthermore, as the reference materials from which the CO_2 emission factors were quoted used HHV, LHV was calculated from this using the conversion factor shown below (Institute of Energy Economics, Japan (IEEJ) [1999]).

- Coal : LHV ← HHV * 0.96
- Oil : LHV ← HHV * 0.93
- LNG : LHV ← HHV * 0.90
- LPG : LHV ← HHV * 0.92

Additionally, regarding conversion factors for petroleum based fuels, in principle, the values given in New Energy and Industrial Technology Development Organization (NEDO) [1995] were used and shortfalls were covered using International Energy Agency (IEA) values given by K.K.Sekiyutsushinsha [2002]. For reference, NEDO [1995] conversion factors were calculated to equalize Yuasa *et al.* [1991] CO_2 emission factors and Science and Technology Agency [1992] CO_2 emission factors.

Table 1.3 Heating values and CO_2 emission factors

	Factor		Heating Value			CO_2 emission factor	
		Ref.	HHV	LHV	Ref.	[kg-CO_2]	Ref.
Coal for coking (import)			28.9 MJ/kg	27.7 MJ/kg	3)	2.61 kg/kg	4)
Coal for general use (import)			26.6 MJ/kg	25.5 MJ/kg	3)	2.39 kg/kg	4)
Coal for general use (domestic)			22.5 MJ/kg	21.6 MJ/kg	3)	1.97 kg/kg	4)
Anthracite (import)			27.2 MJ/kg	26.1 MJ/kg	3)	2.45 kg/kg	4)
Coke			30.1 MJ/kg	28.9 MJ/kg	3)	3.25 kg/kg	4)
Coke Oven Gas			21.1 MJ/Nm^3	19.0 MJ/Nm^3	3)	0.85 kg/Nm^3	4)
Blast Furnace Gas			3.4 MJ/Nm^3	3.1 MJ/Nm^3	3)	0.37 kg/Nm^3	4)
Oxygen Steel Furnace Gas			8.4 MJ/Nm^3	7.6 MJ/Nm^3	3)	0.91 kg/Nm^3	4)
Crude oil	0.8596 kg/L	1)	38.2 MJ/L 44.4 MJ/kg	35.5 MJ/L 41.3 MJ/kg	3)	2.64 kg/L 3.07 kg/kg	4)
NGL / gas-condensate	0.7365 kg/L	1)	35.3 MJ/L 47.9 MJ/kg	32.8 MJ/L 44.6 MJ/kg	3)	2.40 kg/L 3.26 kg/kg	4)
LPG	0.5500 kg/L	2)	50.2 MJ/kg	46.2 MJ/kg	3)	2.94 kg/kg	4)
Naphtha	0.7274 kg/L	1)	34.1 MJ/L 46.9 MJ/kg	31.7 MJ/L 43.6 MJ/kg	3)	2.22 kg/L 3.06 kg/kg	4)
Gasoline	0.7532 kg/L	1)	34.6 MJ/L 45.9 MJ/kg	32.2 MJ/L 42.7 MJ/kg	3)	2.38 kg/L 3.16 kg/kg	4)
Jet Fuel	0.7834 kg/L	2)	36.7 MJ/L 46.8 MJ/kg	34.1 MJ/L 43.6 MJ/kg	3)	2.46 kg/L 3.14 kg/kg	4)
Kerosene	0.7990 kg/L	1)	36.7 MJ/L 45.9 MJ/kg	34.1 MJ/L 42.7 MJ/kg	3)	2.51 kg/L 3.15 kg/kg	4)
Diesel	0.8299 kg/L	1)	38.2 MJ/L 46.0 MJ/kg	35.5 MJ/L 42.8 MJ/kg	3)	2.64 kg/L 3.19 kg/kg	4)
A-Heavy fuel oil	0.8430 kg/L	2)	39.1 MJ/L 46.4 MJ/kg	36.4 MJ/L 43.1 MJ/kg	3)	2.80 kg/L 3.32 kg/kg	4)
B-Heavy fuel oil	0.9000 kg/L	2)	40.4 MJ/L 44.9 MJ/kg	37.6 MJ/L 41.7 MJ/kg	3)	2.91 kg/L 3.23 kg/kg	4)
C-Heavy fuel oil	0.9130 kg/L	1)	41.7 MJ/L 45.7 MJ/kg	38.8 MJ/L 42.5 MJ/kg	3)	2.99 kg/L 3.27 kg/kg	4)
Lubricant	0.8800 kg/L	1)	40.2 MJ/L 45.7 MJ/kg	37.4 MJ/L 42.5 MJ/kg	3)	2.89 kg/L 3.29 kg/kg	4)
Asphalt & other res. oil prds			42.3 MJ/kg	39.3 MJ/kg	3)		
Hydrocarbon Oil			41.0 MJ/L	38.2 MJ/L	5)	3.12 kg/L	5)
Petroleum Coke			35.6 MJ/kg	33.1 MJ/kg	3)	3.31 kg/kg	4)
Refinery Gas			44.9 MJ/Nm^3	41.8 MJ/Nm^3	3)	2.41 kg/Nm^3	4)
Hydrocarbon oil gas			39.4 MJ/Nm^3	35.4 MJ/Nm^3	5)	2.04 kg/Nm^3	5)
Associated gas			48.3 MJ/Nm^3	43.5 MJ/Nm^3	7), 8)	2.67 kg/Nm^3	7)
Off gas			39.3 MJ/L	36.6 MJ/L	6)	2.05 kg/L	6)
LNG	0.7173 kg/Nm^3	1)	54.5 MJ/kg	49.1 MJ/kg	3)	2.77 kg/kg	4)
Natural gas (domestic)			40.9 MJ/Nm^3	36.8 MJ/Nm^3	3)	2.09 kg/Nm^3	4)
City Gas 13A			46.1 MJ/Nm^3	41.4 MJ/Nm^3	9)	2.36 kg/Nm^3	4)

[Source]
1) NEDO [1995]
2) K.K.Sekiyutsushinsha [2002] *IEA basis
3) ANRE [2002-1]
4) MOE [2002-1]
5) PEC [2000]
6) PEC [2002-2]
7) Shigeta, J. [1990]
8) PEC [1998]
9) IEEJ [1999]

Table 1.4 Energy consumptions[*1] and CO_2 emissions from fuel combustion at power generation sector in Japan

	per 855,488*10^6 kWh[*2]			per kWh of power generated					
	Energy consumption			Energy consumption				CO_2 emission factor	
	HHV	LHV		HHV	LHV		%		
Coal (import)	1,525	1,464	* 10^{15} J	1.78	1.71	MJ	(18.1%)	0.1604	kg-CO_2
Crude Oil	296	275	* 10^{15} J	0.35	0.32	MJ	(3.5%)	0.0239	kg-CO_2
C-HFO	484	450	* 10^{15} J	0.57	0.53	MJ	(5.8%)	0.0405	kg-CO_2
Diesel	9	8	* 10^{15} J	0.01	0.01	MJ	(0.1%)	0.0007	kg-CO_2
Naphtha	4	4	* 10^{15} J	0.00	0.00	MJ	(0.0%)	0.0003	kg-CO_2
NGL	2	2	* 10^{15} J	0.00	0.00	MJ	(0.0%)	0.0002	kg-CO_2
LNG	2,107	1,896	* 10^{15} J	2.46	2.22	MJ	(25.1%)	0.1251	kg-CO_2
LPG	20	18	* 10^{15} J	0.02	0.02	MJ	(0.2%)	0.0014	kg-CO_2
Natural gas	22	20	* 10^{15} J	0.03	0.02	MJ	(0.3%)	0.0013	kg-CO_2
COG	61	55	* 10^{15} J	0.07	0.06	MJ	(0.7%)	0.0029	kg-CO_2
LDG / BFG	146	131	* 10^{15} J	0.17	0.15	MJ	(1.7%)	0.0184	kg-CO_2
Wastes	19	19	* 10^{15} J	0.02	0.02	MJ	(0.2%)	0[*3]	kg-CO_2
Geothermal	29	29	* 10^{15} J	0.03	0.03	MJ	(0.3%)	0[*3]	kg-CO_2
Hydro	787	787	* 10^{15} J	0.92	0.92	MJ	(9.4%)	0[*3]	kg-CO_2
Nuclear	2,892	2,892	* 10^{15} J	3.38	3.38	MJ	(34.4%)	0[*3]	kg-CO_2
Total	8,403	8,051	* 10^{15} J	9.82	9.41	MJ	(100.0%)	0.375	kg-CO_2

*1) Actual values of FY2000 in Japan

*2) Amount supplied from power producers to final energy consumption

*3) CO_2 emissions at waste power generation, geothermal power generation, hydropower generation and nuclear power generation are considered as 0.

[Source] ANRE [2002-1]

Power generation process data based on the average electricity configuration of the relevant country was referenced regarding electricity input into overseas processes. Energy consumption values of each country (China, Indonesia, Malaysia, India, United Kingdom, France, Holland, European Union, Russia, United States, Canada, Brazil, South Africa, and Australia) during power generation and CO_2 emission factors during fuel combustion are shown in Table 1.5.

Table 1.5 Energy consumptions and CO_2 emissions from fuel combustion at power generation sector by country (per kWh: receiving end basis, actual results of CY2001)

Country	Energy consumption			CO_2 emission factor	Loss	Source
	HHV	LHV				
China	12.68	12.19	MJ	1.034 kg-CO_2	0.083	IEA [2003-2]
Indonesia	12.49	11.75	MJ	0.767 kg-CO_2	0.135	IEA [2003-2]
Malaysia	9.48	8.62	MJ	0.492 kg-CO_2	0.060	IEA [2003-2]
India	18.42	17.68	MJ	1.490 kg-CO_2	0.294	IEA [2003-2]
UK	11.10	10.57	MJ	0.564 kg-CO_2	0.088	IEA [2003-1]
France	11.52	11.46	MJ	0.069 kg-CO_2	0.062	IEA [2003-1]
Holland	10.88	10.06	MJ	0.637 kg-CO_2	0.039	IEA [2003-1]
EU	10.72	10.37	MJ	0.420 kg-CO_2	0.063	IEA [2003-2]
Russia	18.07	16.87	MJ	0.927 kg-CO_2	0.141	IEA [2003-2]
USA	12.09	11.61	MJ	0.712 kg-CO_2	0.061	IEA [2003-1]
Canada	7.43	7.24	MJ	0.264 kg-CO_2	0.079	IEA [2003-1]
Brazil	6.05	5.94	MJ	0.111 kg-CO_2	0.159	IEA [2003-2]
South Africa	14.15	13.62	MJ	1.206 kg-CO_2	0.091	IEA [2003-2]
Australia	13.90	13.29	MJ	1.157 kg-CO_2	0.082	IEA [2003-1]

2. Well-to-Tank Data Compilation Procedures and Calculation Methods

2.1 Petroleum Based Fuel Production Pathways

2.1.1 Abstract

Fuels derived from petroleum include current diesel, low sulfur diesel, ultra low sulfur diesel, current gasoline, future gasoline, kerosene, naphtha, LPG and heavy fuel oil. Of these, concerning diesel and gasoline (including future types), which are both currently used as fuels for motor vehicles, this study assumes that the supply route would remain similar to that of existing routes (same applies to on-board reforming type FCVs). Post-petroleum refining LPG is handled comprehensively in "2.5 Liquefied Petroleum Gas (LPG) Production Pathways". Regarding other petroleum based products; this study assumes that such products will be supplied to vehicles following some form of conversion.

(1) Diesel

Colorless or fluorescent russet colored petroleum products with gravity ranging from 0.805-0.850, boiling range 180-350 degrees C, distilled after the kerosene fraction during crude distillation. Although the main usage is in automotive, rail and shipping industries, diesel fuel is also used in ceramic and steel industries as well as for supplementary fuel in electricity production. The characteristics of diesel include ignitability, low temperature fluidity (high Cetane Number), good viscosity and low sulfur content. In particular, in line with environmental measures, sulfur content was lowered to less than 0.2 wt% from the previous content of less than 0.5 wt% in 1992, and subsequently lowered to less than 0.05 wt% from October 1997.

Furthermore, permissible limits of sulfur content in diesel fuel will be amended to 0.005 wt% in 2005 (Ministry of the Environment (MOE) [2003-1]). Moreover, MOE [2003-2] reports that from 2007 it will be appropriate to set 0.001 wt% as the permissible limit target value. For these reasons, this study defines diesel with 0.05 wt% sulfur content as "current diesel", 0.005 wt% sulfur content as "low sulfur diesel" and 0.001 wt% sulfur content as "ultra low sulfur diesel", and seeks to quantify each type.

(2) Gasoline

Gasoline refers to petroleum products obtained from crude at the lowest boiling fraction (about 30-220 degrees C), which are in liquid form at normal temperature. Variations in production technique separate gasoline into natural gasoline, straight-run gasoline, reformed gasoline, cracked gasoline, synthetic gasoline, and so on. In chemical terms, all these are hydrocarbon compounds ranging from carbon number 4-12. Although gasoline is separated into industrial grade and fuel grade depending on usage, gasoline for automotive usage falls into the latter category and is manufactured through the mixture of a variety of gasoline components. The most important aspect of automotive gasoline is the anti-knock property, indicated by the octane number. In Japan, the octane number for regular gasoline is approximately 90 and the octane number for premium gasoline is approximately 100. The removal of lead from gasoline has been in practice for regular gasoline since February 1975, and since October 1983 for premium gasoline. In addition, concerning aromatic and olefin content, many oil companies implement self-regulation as part of their environmental measures. Furthermore, concerning benzene, a figure of less than 5% was adopted as the standard since the liberalization of manufactured imports in April 1996.

As with diesel, from 2005 the permissible limit of sulfur content in gasoline will be amended from 0.01 wt% to 0.005 wt% (MOE [2003-1]). For these reasons, this study defines gasoline with 0.01 wt% sulfur content as "current gasoline" and 0.005 wt% sulfur content as "future gasoline", and seeks to quantify each type.

(3) Kerosene

The name "kerosene" predates the invention of the automobile and can be said to be a legacy of a time when diversification of petroleum products had not occurred and kerosene, as a source of light, was the only petroleum product in use. The kerosene fraction has a gravity ranging from 0.78-0.83, and a boiling range of 145-300 degrees C. Specifically, during crude distillation, the distillation of the kerosene fraction takes place between the distillation of gasoline and diesel, with sulfur content and other impurity removal and refining mainly conducted through hydro-treatment, producing a colorless or citrine transparent product with a petroleum odor. The carbon-hydrogen ratio (C/H Ratio) within kerosene constituents is 6-7, specifically 86-88 wt% carbon to 12-14 wt% hydrogen. Kerosene is not used directly as a fuel for automobiles and in this study, kerosene is considered as a resource for hydrogen production through steam reforming.

(4) Naphtha

In many cases, the term "naphtha", as used in United States, refers to heavy gasoline, whereas in Japan the term is largely used in reference to unrefined gasoline (semi-product gasoline). The boiling range is about 30-200 degrees C. The main use of naphtha, when shipped as naphtha, is petrochemical, specifically as a resource for thermal cracking in the production of ethylene, propylene, butadiene, and so on. As with kerosene, naphtha is considered in this study mainly as a resource for hydrogen production through steam reforming.

(5) LPG

LPG is a hydrocarbon with carbon number 3 or 4, specifically propane, propylene, butane, butylene, or other petroleum products with these as the main constituents. Although LPG is a gas under normal temperature and pressure conditions, it can easily be converted to liquid form at relatively low pressures and moderate cooling. Colorless and odorless, with a liquid gravity of 0.50-0.58, and gas gravity at 1.5-2.0 in relation to air at 1.0, LPG accumulates in low places in the event of leakage. In Japan, as a fuel for automobiles, LPG is mainly used in taxis.

(6) Heavy Fuel Oil

Heavy fuel oils are used for internal combustion in diesel engines and gas turbines, and for external combustion in boilers and all types of industrial furnaces, as a mineral oil with suitable qualities, with types and quality standards set forth in the Japanese Industrial Standards (JIS). Heavy fuel oil products are produced through the mixture of high viscosity oils such as topper residue, vacuum residue and solvent deasphalting residue with low viscosity oils such as straight-run diesel and cracked diesel, in accordance with the desired properties, such as viscosity, sulfur content, pour point, flash point and carbon residue content. In this study, heavy fuel oils are considered as fuels for power generation.

Above content is drawn from Japan National Oil Corporation (JNOC) [1986], Taki [1997], Japan Petroleum Institute (JPI) [1998].

2.1.2 Procedures for data collection of unit process

The fuel production pathway flow for petroleum based fuels examined in this study are shown in Figure 2.1.1:

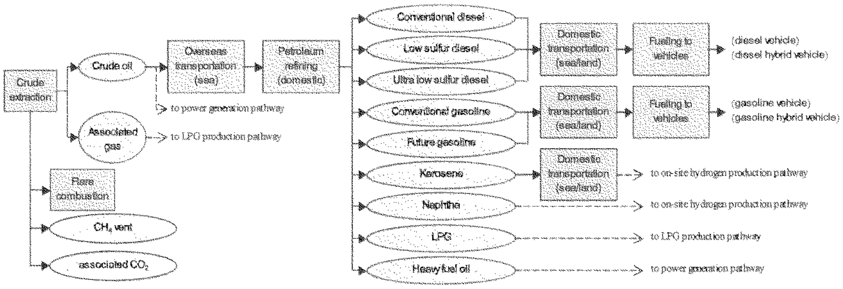

Crude extraction
Crude oil
Overseas transportation (sea)
Petroleum refining (domestic)
to power generation pathway
Associated gas
to LPG production pathway
Flare combustion
CH_4 vent
associated CO_2
Conventional diesel
Low sulfur diesel
Ultra low sulfur diesel
Conventional gasoline
Future gasoline
Kerosene
Naphtha
LPG
Heavy fuel oil
Domestic transportation (sea/land)
Fueling to vehicles
(diesel vehicle)
(diesel hybrid vehicle)
Domestic transportation (sea/land)
Fueling to vehicles
(gasoline vehicle)
(gasoline hybrid vehicle)
Domestic transportation (sea/land)
to on-site hydrogen production pathway
to on-site hydrogen production pathway
to LPG production pathway
to power generation pathway

Figure 2.1.1 Pathway flow for petroleum based fuels

Regarding the refining process of petroleum products overseas and processes related to the import of such products, in relation to diesel and gasoline currently used as automobile fuel, as the amount refined overseas is small in comparison to the amount refined domestically (less than 3%), the omission of these processes is considered appropriate. On the other hand, while it is also a petroleum product, in relation to naphtha, which is mainly for petrochemical purposes, the amount refined and imported from overseas is greater than the amount refined domestically (see Table 2.1.1). Accordingly, when considering naphtha as an intermediary product in the production pathway of automobile fuels, the consideration of overseas petroleum refining processes and naphtha import processes (transportation via sea) may become necessary. However, as the information necessary for the creation of inventory data regarding overseas refining processes was unobtainable, for this study, these processes have been treated as beyond the system boundary.

Table 2.1.1 Amount of domestic and imported production of petroleum products [Unit: 10^3 kL]

	Diesel	Gasoline	Naphtha	Kerosene	A-heavy fuel	C-heavy fuel
Domestic	41,530 (97.0%)	58,216 (98.0%)	18,501 (39.7%)	27,366 (93.1%)	28,166 (96.7%)	32,332 (97.6%)
Imported	1,306 (3.0%)	1,215 (2.0%)	28,129 (60.3%)	2,030 (6.9%)	973 (3.3%)	780 (2.4%)

[Source] METI [2002]

(1) Crude Extraction

<i> Existing Study

As gas production generally accompanies crude extraction, the majority of oil fields use this associated gas as the energy source for the operation of the extraction facilities. The amount of associated gas required for the extraction of crude, based only on information from the Arabian Oil Co., Ltd., as shown in Institute of Applied Energy (IAE) [1990] (p.118), stands at 23 SCF/B[1], while Petroleum Energy Center (PEC) [1998] (p.17) gives a figure of 50-60 SCF/B based on the results of a hearing survey conducted with oil fields in the UAE and Saudi Arabia, both major suppliers of crude to Japan (60 SCF/B is used for calculation purposes). In addition, following on from PEC [1998], PEC [2002-2] (p.18) also uses 60 SCF/B for calculation purposes.

<ii> This Study

60 SCF/B, used both in PEC [1998] and PEC [2002-2], is also used in this study. For the composition of associated gas, the composition given in IAE [1990], used by both PEC [1998] and Shigeta [1990], was adopted. This is the weighted average derived from the composition of associated gases of Middle East oil fields. From this composition and the higher heating value set out for each gas in PEC [1998], it is possible to calculate the heating values for associated gases and CO_2 emission factors during combustion.

(2) Flare Combustion

<i> Existing Study

Associated gas excess to the requirements of the crude extraction process is burnt off at the flare stack. Shigeta [1990] and PEC [1998] (p.20) calculate flare stack energy expenditure and CO_2 emissions. Shigeta [1990] sets out the associated gas oil ratio (Gas Oil Ratio, GOR) for Middle East light crude oil fields, Middle East heavy crude oil fields, Southeast Asia and China (source unknown). On the other hand, PEC [1998] reasons that the Middle East and Indonesia account for the majority of crude imports to Japan and sets out GOR for each country. Where available, information from the Information Center for Petroleum Exploration and Production (ICEP) database was used, and unknown values were estimated from API gravity and location. Calculations in either report are based on flare ratio figures (proportion of associated gases burnt off at the flare stack) given in Organization of the Petroleum Exporting Countries (OPEC) Annual Reports (1987 Report used by Shigeta [1990], 1995 Report used by PEC [1998]). In addition, while PEC [2002-2] (p.19) follows the calculation method used in PEC [1998], flare ratio settings have been updated using data from the 1999 OPEC Annual Statistical Bulletin.

<ii> This Study

This study follows the calculation methods used in PEC [1998]. Regarding crude import volume, from the relationship with data gathered in relation to domestic petroleum refining, although the data is slightly dated, actual values from 1997 given in Ministry of International Trade and Industry (MITI) [1998] were used. In addition, GOR values set out for each country in PEC [1998] were used. Flare ratios for each country were calculated from total production and flare amount figures of the natural gas production volume breakdown given in OPEC [2001]. In addition, regarding Middle East countries for which flare related information was not available, weighted average values calculated using values from Middle East countries with clear flare ratios and import volumes were used.

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[1] 1 SCF (standard cubic feet) = 0.0263 Nm^3, 1B (barrel) = 158.9873 litre

(3) Associated CO_2

<i> Existing Study

Regarding CO_2 content of associated gas (emissions into the atmosphere) other than from in-house consumption or flared; IAE [1990] and Shigeta [1990] calculate values based on the associated gas composition.

<ii> This Study

According to IAE [1990], as the percentage of CO_2 in associated gas is 5.8%, associated CO_2 volume was calculated by multiplying the desired associated gas volume by this percentage.

(4) CH_4 Vent

<i> Existing Study

Regarding CH_4 vent during crude extraction, the carbon equivalent is given in Central Research Institute of Electric Power Industry (CRIEPI) [1992] (p.32) and IEEJ [1999] (p.23). Of these, the basis for the figure given in CRIEPI [1992] is unclear. In addition, IEEJ [1990] assumes that there is no CH_4 vent during crude extraction and that leakage occurs only during associated gas production, and a theoretical calculation is used to calculate the value.

<ii> This Study

Calculations in this study are based on values given in IEEJ [1999]. Furthermore, although the heating value given in this literature is HHV and CO_2 emissions are given as the carbon equivalent when the characterization factor for CH_4 global warming is set at 21, this study conducts calculation into CO_2 equivalent using the value 23, shown in Table 1.2. In addition, this study has also taken energy loss through CH_4 vent into consideration.

(5) Overseas Transportation (Sea)

<i> Existing Study

Large ocean tankers are used to transport crude oil from crude producing countries to Japan. While IAE [1990] (p.38) states that Southeast Asia and China use 100,000 t tankers and the Middle East/other regions use 250,000 t tankers, PEC [1998] (p.33) states 80,000 t tankers for China, 100,000 t tankers for North

America and Oceania, and 250,000 t tankers for the Middle East and other regions, with both calculating fuel consumption factor per region from the fuel consumption of each ocean tanker.

Regarding calculations, while IAE [1990] considered only the passage, PEC [1998] (p.34) also takes fuel consumption while moored and for cargo heating for high viscosity crude into consideration. Regarding calculation method, PEC [1998] sought the weighted average of shipping distance based on import volume for each region and used this figure to calculate fuel consumption for one voyage. IAE [1990] gives no details concerning calculation method.

PEC [2002-2] follows the calculation methods used in PEC [1998].

<ii> This Study

In this study, using the ocean tanker sizes specified in PEC [1998], energy consumption and GHG emissions are calculated inclusive of fuel consumption while moored and for cargo heating.

This study specifies ocean tanker size and shipping distance for each crude producing country and ascertains fuel consumption per voyage per country, and uses the weighted average value relative to import volume in order to calculate fuel consumption per kg of crude. Furthermore, fuel consumption per kg crude for external transportation (sea) was calculated separately for refining or electricity generation depending on intended usage.

Regarding crude import volume, from the relationship with data gathered in relation to domestic petroleum refining, although the data is slightly dated, actual values from 1997 given in MITI [1998] were used. In addition, the marine shipping distance was calculated as the distance from the port of shipment of the crude producing country to the Yokohama Port. Furthermore, regarding Brunei, Iraq, Equatorial Guinea and Congo, as data concerning the distance of crude produced in these countries from the port of shipment was not available, data from relatively nearby countries and regions was substituted.

(6) Refining in Japan

<i> Existing Study

In Shigeta [1990] and PEC [1997] (p.52), energy consumption and environmental burden per unit quantity of petroleum product is calculated from the material balance in the petroleum product producing industry (gross production volume of petroleum products, and input of raw materials/ingredients).

PEC [2000] conducts further subdivision of the refining process of petroleum products and constructs a process flow diagram (PFD). Although energy consumption per product calculations are made based on this diagram, material balance data is cited for product yield settings (p.33-34). CO_2 emissions were calculated from energy consumption during refining per product, derived from material balance data and the PFD, under the assumption that CO_2 emissions are proportionate to energy consumption, as it was considered impossible to gather detailed and accurate data representative of all refineries in Japan for each subdivided refining process and fuel input for each (p.40).

PEC [2002-2] (p.30) also subdivides the refining process and configures a PFD, and calculates energy consumption for each product (current gasoline, future gasoline, current diesel, low sulfur diesel, naphtha) during the refining process, citing JPI [1998] and others, as the calculation basis for heat efficiency. This literature also uses material balance data for CO_2 emissions calculations, multiplying the weighted average value derived from annual total emissions per fuel type in relation to the CO_2 emissions index for the heating value of each fuel type used, by energy consumption per product within the refining process.

All reports source material balance data from the "Yearbook of Production, Supply and Demand of Petroleum, Coal and Coke". Shigeta [1990] from the 1987 edition, PEC [1997] from the 1995 edition, PEC [2000] from the 1997 edition and PEC [2002-2] from the 2000 edition.

<ii> This Study

This study adopted the calculation method used in PEC [2000] to calculate energy consumption and GHG emissions. Although this selection was based on the need to calculate data regarding kerosene, heavy fuel oils and LPG not covered in PEC [2002-2], as the calculations of both these reports are based on the same reasoning, it was inferred that the difference between these reference materials would have little effect on calculation results.

The "Yearbook of Production, Supply and Demand of Petroleum, Coal and Coke" edition used here is the 1997 edition (MITI [1998]). Furthermore, although PEC [2000] uses only actual performance data of refiners, as actual values per refiner given in MITI [1998] were insufficient, general data (inclusive of refiners, lubricant manufacturers, other related industries) was used.

To begin, energy consumption for petroleum refining was calculated. For calculation purposes figures given in MITI [1998] for fuel consumption (p. 50-53), input and yield (p. 68-71), and electricity usage (p.150) were used. Energy consumption (LHV) associated with the consumption of these fuels was 511,514 TJ/year, and CO_2 emissions $31{,}859*10^3$ t-CO_2/year. Furthermore, on top of this energy consumption, PEC [2000] (p. 40-41) includes in-house consumption of catalytic coke and CO gas, and subsequently, this study also includes these factors (LHV/HHV ratio 0.93 for coke, 0.9 for CO gas).

To follow, these were then allocated to each petroleum product using energy consumption per product ratios calculated in PEC [2000] (p.33-34) using the PFD. That is to say, allocation was conducted using the ratio between energy consumption for each product given in PEC [2000] (p.33-34) and their average values (67 L-FOE/kL).

Regarding low-sulfur diesel, according to the trial calculations in PEC [2000] (p.45), the installation of ultra deep hydrodesulfurization unit will increase energy consumption by almost 1.5 times from 42 to 61 L-FOE/kL-Diesel, and increase the overall average for petroleum products from 68 to 71 L-FOE/kL-product. On the other hand, a report referenced by PEC [2002-2] (p.31) states that hydrogen consumption necessary for the desulfurization of 50ppm sulfur content would be 1.3 to 1.5 times greater than for 500ppm. Therefore, for this study, calculations for the required energy consumption for the production of low-sulfur diesel were made based on the trial calculation results of PEC [2000].

In addition, as no information regarding energy consumption for ultra low sulfur diesel and future gasoline was obtainable, calculations were based on the assumption that the ratio in relation to the average would be 2 times that of current diesel for ultra low sulfur diesel at approximately 1.2, and 2.0 for future gasoline.

Furthermore, regarding the process yield of the petroleum refining process (ratio of petroleum products in relation to processed crude volume), the ratio of total petroleum product volume (weight) in relation to processed crude volume (weight) was used.

(7) Domestic Transportation (Sea/Land)

<i> Existing Study

Shigeta [1990] cites CO_2 emissions during domestic transportation at a uniform 10% of CO_2 emissions during marine shipping. In addition, in PEC [1998] (p.43-51) based on the actual transportation status of petroleum products and fuel usage data gathered by the Petroleum Association of Japan (PAJ) in order to formulate the "Oil Industry Voluntary Action Plan for Global Environment Conservation", environmental burden was calculated specifying three transportation types (tanker lorries, coastal tankers, tanker truck). Environmental load calculations in PEC [2002-2] (p. 48-50) are based on PAJ [2000].

<ii> This Study

This study cites data used in PEC [2002-2]. Specifically, energy consumption and GHG emissions during transportation of "white oil" (gasoline, diesel oil, kerosene, naphtha, LPG) and "black oil" (heavey fuel oil) were calculated using the data given on p.49 of the report regarding the domestic overland transportation process of petroleum products, and data given on p.50 regarding coastal transportation. Regarding fuel consumed, diesel was considered as the fuel for the domestic overland transportation process, while for the coastal transportation process, fuel consumption was split into 90% C-heavy fuel oil while under way and 10% A-heavy fuel oil for port entry/exit, based on information provided in PEC [1998] (p.45). In addition, for final results, energy consumption and GHG emissions were calculated based on values obtained through the distribution of fuel consumption over transportation volume, for both domestic overland and coastal transportation.

(8) Fueling to Vehicles

No particular consideration has been given in either this or prior studies concerning energy consumption and GHG emissions during the fueling to vehicles with diesel or gasoline. In addition, this study set the value of such at zero following confirmation through hearing surveys that levels were practically insignificant.

2.1.3 Calculation results

Regarding the production pathways of petroleum based fuels, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.1.2 (energy consumption), Table 2.1.3 (GHG emissions) and Table 2.1.4 (energy efficiency).

Table 2.1.2 WTT energy consumption of petroleum based fuel production pathways [MJ/MJ]

		Conventional diesel	Low sulfur diesel	Ultra low sulfur diesel	Conventional gasoline	Future gasoline	Kerosene	Naphtha	A heavy fuel oil	C heavy fuel oil
Crude oil extraction	Operation	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
	Flare combustion	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Overseas transportation		0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Petroleum refining		0.043	0.089	0.082	0.139	0.151	0.031	0.054	0.067	0.064
Domestic transportation		0.006	0.005	0.005	0.005	0.005	0.006	-	-	-
Fueling to vehicles		0.000	0.000	0.000	0.000	0.000	-	-	-	-
Total		0.078	0.094	0.118	0.175	0.187	0.066	0.084	0.097	0.094

Table 2.1.3 WTT GHG emissions of petroleum based fuel production pathways [g eq-CO_2/MJ]

		Conventional diesel	Low sulfur diesel	Ultra low sulfur diesel	Conventional gasoline	Future gasoline	Kerosene	Naphtha	A heavy fuel oil	C heavy fuel oil
Crude oil extraction	Operation	0.76	0.76	0.76	0.76	0.76	0.76	0.74	0.75	0.76
	Flare combustion	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.39
	Associated CO_2	0.33	0.33	0.33	0.33	0.33	0.33	0.32	0.33	0.33
	CH_4 vent	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04
Overseas transportation		0.92	0.92	0.92	0.92	0.92	0.92	0.90	0.91	0.92
Petroleum refining		2.66	3.64	5.08	8.59	9.36	1.91	3.33	4.14	3.94
Domestic transportation		0.37	0.37	0.37	0.41	0.41	0.39	-	-	-
Fueling to vehicles		0.00	0.00	0.00	0.00	0.00	-	-	-	-
Total		5.45	6.43	7.88	11.42	12.19	4.72	5.70	6.54	6.38

Table 2.1.4 WTT energy efficiency of petroleum based fuel production pathways (LHV)

	Conventional diesel	Low sulfur diesel	Ultra low sulfur diesel	Conventional gasoline	Future gasoline	Kerosene	Naphtha	A heavy fuel oil	C heavy fuel oil
Crude oil extraction	0.982	0.982	0.982	0.982	0.982	0.982	0.982	0.982	0.982
Overseas transportation	0.988	0.988	0.988	0.988	0.988	0.988	0.988	0.988	0.988
Petroleum refining	0.948	0.934	0.915	0.869	0.860	0.957	0.955	0.934	0.9233
Domestic transportation	0.995	0.995	0.995	0.995	0.995	0.995	-	-	-
Fueling to vehicles	1.000	1.000	1.000	1.000	1.000	-	-	-	-
Total	0.916	0.902	0.883	0.839	0.830	0.924	0.927	0.907	0.896

2.2 Natural Gas Based Fuel Production Pathways

2.2.1 Abstract

Natural gas has low energy density and incurs high shipping costs. In order to reduce this shipping cost, it will be necessary to physically or chemically improve the energy density of natural gas. Physical methods of improvement include liquefaction through cooling to produce liquefied natural gas (LNG), compression to produce compressed natural gas (CNG), and hydration for transportation of natural gas in hydrated form.

On the other hand, chemical improvement involves conversion into different substances through chemical processes applied at the wellhead, and mainly involves the conversion of gas into a liquid fuel, hence the technology is called Gas-to-Liquid (GTL). This section concentrates on LNG (physical improvement) and products derived from LNG (e.g. city gas). GTL is covered in "2.4 Synthetic Fuel Production Pathways".

(1) LNG

Natural gas, composed mainly of CH_4, is chilled to ultra low temperatures and liquefied following the removal of impurities such as moisture, sulfur compounds and CO_2 to produce LNG. Natural gas liquefies at approximately -160 degrees C, and is reduced in volume to one six-hundredth that of gas through liquefaction, facilitating convenience of transportation and storage. Accordingly, conversion to LNG for temporary storage is used as a method of peak shaving for natural gas, and LNG conversion of natural gas for transportation is used in cases of transoceanic transportation where natural gas transportation via pipeline is not possible.

The main uses of LNG are for electricity and city gas.

(2) City Gas

City gas refers to "gaseous fuels supplied to gas appliances within buildings through gas pipelines from the gas production facilities of licensed gas industry companies (e.g. Tokyo Gas, Osaka Gas) in accordance with the Gas Utility Industry Law". City gas is adjusted to comply with heating values stipulated in supply regulations through refining and mixing feedstock such as LPG, coal, coke, naphtha, heavy fuel oils and natural gas.

Currently, there are seven types of city gas in use throughout Japan, with different feedstock, production methods and heating values (See Table 2.2.1).

Table 2.2.1 Standard heating values of city gas by gas group

Gas group	Standard heating values
13A	10,000 - 15,000 kcal/m^3
12A	9,070 - 11,000 kcal/m^3
6A	5,800 - 7,000 kcal/m^3
5C	4,500 - 5,000 kcal/m^3
L1	4,500 - 5,000 kcal/m^3
L2	4,500 - 5,000 kcal/m^3
L3	3,600 - 4,500 kcal/m^3

[Source] Japan Gas Association website

Of these, the composition of city gas type 13A, the most commonly used type in within Japan, is shown in Table 2.2.2.

Table 2.2.2 The composition of city gas type 13A

Composition		Content [wt%]
Methane	CH_4	70 - 80
Ethane	C_2H_6	< 10
Propane	C_3H_8	10 - 20
Butane	C_4H_{10}	< 10

[Source] Japan Gas Association website

In this study, concerning supply pathways, other than cases where processing and liquefaction take place at overseas production sites prior to importation as LNG, cases of direct overseas transportation via pipeline (from Sakhalin) were also considered. In addition, for methods fueling to automobiles, other than cases of compressed city gas (CNG vehicles), the direct fueling of LNG (LNG vehicles), which may become popular in the future, was also considered.

2.2.2 Procedures for data collection of unit process

The fuel production pathway flow for natural gas based fuels examined in this study are shown in Figure 2.2.1:

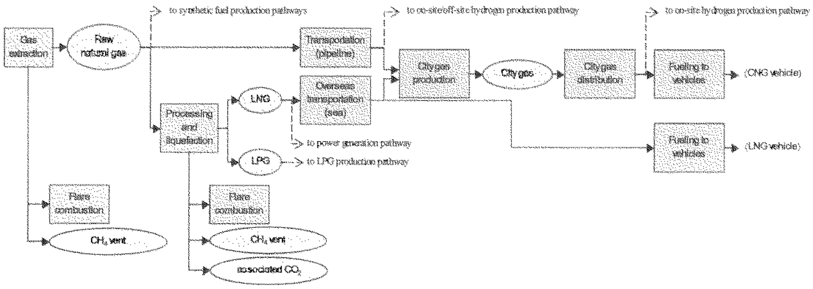

to synthetic fuel production pathways
to on-site/off-site hydrogen production pathway
to on-site hydrogen production pathway
Gas extraction
Raw natural gas
Transportation (pipeline)
City gas production
City gas
City gas distribution
Fueling to vehicles
(CNG vehicle)
LNG
Overseas transportation (sea)
Processing and liquefaction
to power generation pathway
LPG
to LPG production pathway
Fueling to vehicles
(LNG vehicle)
Flare combustion
Flare combustion
CH₄ vent
CH₄ vent
associated CO₂

Figure 2.2.1 Pathway flow for natural gas based fuels production

(1) Natural Gas Extraction

<i> Existing Study

Shigeta [1990] calculates CO_2 emissions from extraction and production (liquefaction) processes based on volume of raw natural gas as feedstock, obtained through the consideration of raw natural gas composition for each producing region and the 1987 import volume ratio.

NEDO [1996] (p.101) adopts the input volumes of A-heavy fuel oil as fuel used during exploration / extraction of natural gas based on data from the Bontang gas fields, Indonesia.

Tamura *et al.* [1999] conducted fields surveys in five source countries/regions of LNG for city gas (Alaska, Indonesia, Malaysia, Brunei, Australia), and calculated the weighted average value through the import volume ratio (1997) for CO_2 emissions based on data obtained from four of these source countries/regions excluding Alaska. Calculations using similar calculation methods and based on similar data are conducted in IEEJ [1999] (p.24). For co-produced LPG, condensate, and so on, both give distributed values on a calorific basis. In addition, apart from the Japan average, IEEJ [1999] also conducts calculations regarding LNG for city gas based on import volume ratio.

PEC [2002-2] calculates energy efficiency based on IEEJ [1999]. In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

This study cites Okamura *et al.* [2004]. However, regarding energy consumption, calculations are made from heating value based fuel ratio data using the entrance to liquefaction facilities as the reference point, obtained from a hearing survey conducted with the Japan Gas Association (JGA) in relation to the content of Okamura *et al.* [2004].

(2) Processing and Liquefaction

<i> Existing Study

IAE [1990] (p.121) provides data for LNG import volumes, raw natural gas composition, raw natural gas processing volumes, natural gas consumption and CO_2 emissions for each country of origin (actual values for 1987). Ogawa *et al.* [1998] calculates fuel ratios from this data and estimates CO_2 emissions from LNG import volumes per gas producing country for 1996. In addition, Hondo *et al.* [1999] also includes Australia as a gas producing country, and uses similar methods to determine the natural gas volumes required for liquefaction. The fuel efficiency determined from the results of these reports is approximately 88 %.

NEDO [1996] gives energy consumption during liquefaction as 9 vol% of natural gas produced, and states that 6 vol% of natural gas produced is associated gas (mainly CO_2). According to these values, fuel efficiency during liquefaction, excluding associated gas, is approximately 90 %.

Although Tamura *et al.* [1999] and IEEJ [1999] (p.24) both calculated the weighted average value through the import volume ratio (1997) for CO_2 emissions based on data obtained from fields surveys conducted in five source countries/regions of LNG for city gas, there are slight discrepancies in the results. Both reports give distributed values on a calorific basis for co-produced LPG, condensate, and so on.

PEC [2002-2] (p.53) calculates fuel efficiency based on IEEJ [1999], with a given result of 92 %.

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

As with the natural gas production (extraction) process, this study cites Okamura *et al.* [2004]. However, regarding energy consumption, calculations are made from heating value based fuel ratio data using the entrance to liquefaction facilities as the reference point, obtained from a hearing survey conducted with the

JGA in relation to the content of Okamura *et al.* [2004].

(3) Flare Combustion

<i> Existing Study

Shigeta [1990] does not conduct calculations for flared gas as the liquefaction facilities and the gas wells of the Japan LNG project are interlinked, and in comparison to the amount of gas consumed in the liquefaction process, the amount flared is practically insignificant. Ogawa *et al.* [1998] gives 4 % as the worldwide average flare combustion ratio in relation to natural gas production for 1996, while also stating that for modern LNG production facilities, the flare combustion ratio is 1 % as the amount of natural gas burnt during production is lower.

Tamura *et al.* [1999] and IEEJ [1999] (p.24) handle flare combustion during extraction and during liquefaction separately, calculating the weighted average value through the import volume ratio (1997) for CO_2 emissions based on data from the previously mentioned fields surveys conducted in five source countries/regions of LNG for city gas, but there are slight discrepancies in the results. Both reports give distributed values on a calorific basis for co-produced LPG, condensate, and so on.

PEC [2002-2] (p.53) calculates fuel efficiency based on IEEJ [1999].

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

As with the other processes, this study cites Okamura *et al.* [2004]. However, regarding energy consumption, calculations are made from heating value based fuel ratio data using the entrance to liquefaction facilities as the reference point, obtained from a hearing survey conducted with the JGA in relation to the content of Okamura *et al.* [2004].

(4) Associated CO_2

<i> Existing Study

IAE [1990] multiplies the raw natural gas input to liquefaction plants given per gas producing country by the CO_2 content percentage of raw natural gas, and calculates associated CO_2 by obtaining the weighted average through the import volume ratio of 1987. Based on this, Ogawa *et al.* [1998] conducts similar calculations using import data for 1996.

Tamura *et al.* [1999] gives the weighted average value of wellheads for CO_2 content.

Other than the previously mentioned fields surveys conducted in five source countries/regions of LNG for city gas, IEEJ [1999] (p.24) also applies and reflects data for Arun, Qatar and Abu Dhabi, taken from 1996 survey materials from the JNOC, and gives the results of calculations for emissions by heating value (distributed values on a calorific basis for co-produced LPG, condensate, and so on).

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

Okamura *et al.* [2004] is also cited here.

(5) CH_4 Vent

<i> Existing Study

As with flare combustion, Ogawa *et al.* [1998] estimates CH_4 vent ratio at approximately 1 % in relation to natural gas production volume. Although the basis is unclear, CRIEPI [1992] (p.32) gives amounts for CH_4 vent during extraction and liquefaction.

Tamura *et al.* [1999] and IEEJ [1999] (p.24) both separate the source of leakage into each production/liquefaction process, and calculate CH_4 vent by obtaining the weighted average value from import volume (1997) based on data from the previously mentioned field surveys conducted in five source countries/regions of LNG for city gas, but there are slight discrepancies in the results. Both reports give distributed values on a calorific basis for co-produced LPG, condensate, and so on.

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

As with the other processes, this study cites Okamura *et al.* [2004]. However, regarding energy consumption, calculations are made from heating value based fuel ratio data using the entrance to liquefaction facilities as the reference point, obtained from a hearing survey conducted with the JGA in relation to the content of Okamura *et al.* [2004].

In addition, regarding the characterization factor for global warming, conversions back into CO_2 equivalent are conducted using the value used in this study (see Table 1.2).

(6) Overseas Transportation (Sea)

<i> Existing Study

IAE [1990] (p.125) calculates CO_2 emissions per unit weight of LNG from the fuel consumption during passage of 125,000 m^3 class LNG vessels (return trip, boil off gas (BOG) and petroleum fuel usage), and the import volumes and distance from each gas producing country.

NEDO [1996] (p.105) calculates the amount of A-heavy fuel oil required for transportation of the annual LNG requirement for a LNG combined cycle plant (513,000 tons), using a 125,000 m^3 capacity (53,750 t) vessel with a mileage of 63 kg-A-heavy fuel oil/km over a distance of 5,000km, taking the return trip into consideration.

Hondo *et al.* [1999] asserts that the fuel during passage is the BOG of LNG and calculates the environmental burden of transportation per unit weight of LNG from the boil off ratio of a 125,000 m^3 class LNG vessel, import volume and distance from each gas producing country, and fuel consumption while moored (LNG usage).

Tamura *et al.* [1999] calculates the CO_2 emission factors for t-km from the actual records (1997) of LNG transportations from the Bontang gas fields in Indonesia, and then calculates CO_2 emissions per unit heat of LNG during overseas transportation using the weighted average of shipping distance from each country and import volume (1997). Furthermore, the fuels used are BOG and C-heavy fuel oil.

IEEJ [1999] (p.25) calculates CO_2 emissions of LNG during overseas transportation by using the weighted average of import volume ratio (1997) and actual data for 1997 gathered from 44 of the 65 LNG shipping vessels that carry LNG to Japan, in relation to BOG and C-heavy fuel oil consumption, LNG load, and shipping distance.

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999].

<ii> This Study

This study cites Okamura *et al.* [2004]. However, regarding energy consumption, calculations are made from data pertaining to LNG vessel fuel consumption, LNG load, weighted average values for transportation distances one-way, obtained from a hearing survey conducted with the JGA in relation to the content of Okamura *et al.* [2004]. Furthermore, separate calculations were conducted for overall LNG and LNG for city gas.

(7) Overseas Transportation via Pipelines

<i> Existing Study

Regarding the transportation of natural gas via pipelines, as a report focusing on supply within Japan, the Economic Research Center, Fujitsu Research Institute (FRI-ERC)[2000] report calculates CO_2 emissions, and states that for a shipping distance of less than 16,000 km, transportation via pipeline is better than LNG transportation.

<ii> This Study

In this study, energy consumption and GHG emissions are calculated from data related to pipeline transportation obtained through hearing surveys (approximately 50 kW per km pipeline for 880 MCF/day natural gas output). Furthermore, the power generating efficiency of natural gas output energy (assuming generation through natural gas) is 15 %.

Regarding transportation distance, the pipeline transportation distance considered in this study (2,000 km) is the distance from Sakhalin to Japan, given in Koide [2000] as the distance from Korsakov to Niigata (approx 1,400 km) plus the distance from Niigata to Fukui (approx 600 km).

In addition, regarding the heating value and CO_2 emission factors for natural gas produced in Sakhalin, calculations were made using global natural gas composition data given in the Agency for Natural Resources and Energy (ANRE)[1992] (p.110) for natural gas produced in the former Soviet Union.

(8) City Gas Production and Distribution

<i> Existing Study

Although Tamura *et al.* [1999] and IEEJ [1999] (p.25) both calculate CO_2 emissions based on actual energy consumption figures (1996) for processes such as re-gasification of LNG and heating value adjustment for the domestic LNG facilities of three gas companies, there are slight discrepancies in the results. Both reports consider environmental burden from the upstream process for LPG input for heating value adjustment, and also considers CO_2 reductions from the cold usage of LNG. Regarding the distribution process, as the energy from the pump that pressurizes LNG before re-gasification is used, this is already included in the city gas production process.

Based on values given in IEEJ [1999], PEC [2002-2] (p.60) calculates fuel efficiency to be 99.8 %.

In addition, Okamura *et al.* [2004] gives data calculated after the addition of survey details related to the Middle East Project (Qatar, Oman) to the survey results of IEEJ [1999]. As with IEEJ [1999], LPG for heating value adjustment and cold usage of LNG are also considered.

<ii> This Study

The environmental burden of the city gas production process itself can be calculated using statistics given in ANRE [2002-2]. However, it is difficult to calculate the environmental burden for in-house consumption of LNG, city gas, and so on, from this information alone. Therefore, calculations in this study are based on the hearing survey conducted with the JGA in relation to the content of Okamura *et al.* [2004].

Although Okamura *et al.* [2004] considers the CO_2 emissions reduction effect of cold usage, this study does not consider aspects that are not directly related to the production process of automotive fuels.

(9) Fueling to Vehicles

<i> Existing Study

PEC [2002-2] gives 95 % as the energy efficiency of the compression/fueling process for CNG vehicles at service stations, the default value of the model developed at the U.S. Argonne National Laboratory (ANL) for the evaluation of environmental effect of automotive fuels "GREET 1.6" (ANL [2001]). From the assumption that the power source for the compression device is either natural gas or electricity, and that both will be used in equal measure, calculations are based on the assumption that for the U.S., CNG vehicles will be filled with natural gas compressed to 3,000 lb/in^2 (= approx. 200 kg/cm^2). Furthermore, "GREET 1.6" gives the default value for the energy efficiency of compression devices using natural gas as 93 %, and 97 % for devices using electricity.

<ii> This Study

Of the natural gas powered vehicles currently in use, CNG vehicles are the most common. In Japan, compression devices (normally 250 m^3/h) are used to compress medium pressure gas received through pipelines to pressures higher (approx. 25 MPa) than the maximum fueling pressure for vehicles (20 MPa).

In this study, calculations for energy consumption and GHG emissions of the fueling process for CNG and

LNG vehicles are based on natural gas fueling station data obtained through a hearing survey conducted with the JGA and others.

[Fueling to CNG vehicle]

Given that the rated output of a 250 m^3/h compression device is 55 kW (medium pressure A) and 75 kW (medium pressure B), energy consumption is calculated under the assumption that, for both, the compression device is operated at 85 % rated power when fueling to a CNG vehicle.

[Fueling to LNG vehicle]

Regarding LNG vehicles, energy consumption estimations for fueling to LNG vehicles are made based on the LNG pump discharge rate and the output of electric motors given in Organization for the Promotion of Low Emission Vehicles (LEVO) [2003] (p.86). In addition, natural vaporization of LNG while in storage is also considered.

2.2.3 Calculation results

Regarding the production pathways of natural gas based fuels, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.2.3 (energy consumption), Table 2.2.4 (GHG emissions) and Table 2.2.5 (energy efficiency).

Table 2.2.3 WTT energy consumption of natural gas based fuel production pathways [MJ/MJ]

		LNG	City gas to CNG vehicle	
			From LNG (conventional)	From pipeline gas
Natural gas extraction	Operation	0.011	0.011	0.011
	Flare combustion	0.002	0.002	0.002
Processing / liquefaction	Operation	0.102	0.100	-
	Flare combustion	0.009	0.008	-
Overseas transportation	Sea	0.036	0.030	-
	Pipeline	-	-	0.054
Production / distribution	Operation	-	0.004	0.004
	LPG addition	-	0.005	0.005
Fueling to vehicles		0.000	0.046	0.046
Total		0.161	0.206	0.120
Reduction by cold heat utilization			△ 0.004	

Table 2.2.4 WTT GHG emissions of natural gas based fuel production pathways [g eq-CO_2/MJ]

		LNG	City gas to CNG vehicle	
			From LNG (conventional)	From pipeline gas
Natural gas extraction	Operation	0.56	0.54	0.48
	Flare combustion	0.17	0.17	0.15
	CH_4 vent	0.25	0.24	0.22
Processing / liquefaction	Operation	6.11	5.60	-
	Flare combustion	0.48	0.39	-
	Associated CO_2	2.17	1.77	-
	CH_4 vent	0.64	0.55	-
Overseas transportation	Sea	2.28	1.89	-
	Pipeline	-	-	3.09
Production / distribution	Operation	-	0.21	0.21
	LPG addition	-	0.34	0.34
Fueling to vehicles		0.01	1.82	1.82
Total		12.68	13.52	6.30
Reduction by cold heat utilization			△ 0.34	

Table 2.2.5 WTT energy efficiency of natural gas based fuel production pathways (LHV)

		LNG	City gas to CNG vehicle	
			From LNG (conventional)	From pipeline gas
Natural gas extraction		0.987	0.987	0.987
Processing / liquefaction		0.901	0.903	-
Overseas transportation	Sea	0.965	0.971	-
	Pipeline	-	-	0.949
Production / distribution of city gas		-	0.998	0.998
Fueling to vehicles		1.000	0.983	0.983
Total		0.858	0.848	0.918

2.3 Fuel Production Pathways from Biomass Resources

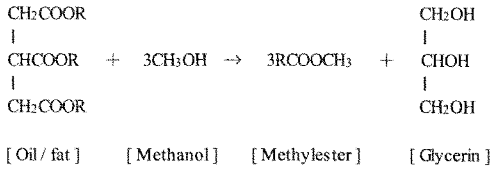
2.3.1 Abstract

Although the term "Biomass", a compound term consisting of "bio" signifying organisms and "mass" signifying quantity or weight, is generally used in biology, it has in recent years come to be used frequently in reference to subjects such as "Organisms as a resource for energy and industrial materials" (Yamaji *et al.* [2000]) and "Substantial plant based substances that can be used for energy" (Yokoyama [2001]). From the perspective of usage as fuel, biomass can be categorized into liquid fuel production processes and gaseous fuel (intermediate product) production processes.

This section looks into bio-diesel fuel (BDF) production (esterification) and ethanol conversion as methods of liquid fuel production, and CH_4 fermentation as a method of gaseous fuel production. Furthermore, regarding CH_4 fermentation, this section focuses on the process up to distribution into the natural gas supply line after production following fermentation, and considers the processes after this point (e.g. fueling to CNG vehicle, syngas production, hydrogen production) to be the same as for natural gas.

(1) BDF

Bio diesel fuel (BDF) is a general term used in reference to methyl esters of higher fatty acid obtained when a transesterification reaction takes place between vegetable oils (ester of glycerin and higher fatty acids) and methanol in the presence of a catalyst. The chemical reaction to obtain BDF is as follows.



$$\begin{array}{lcccccl} CH_2COOR & & & & & & CH_2OH \\ | & & & & & & | \\ CHCOOR & + & 3CH_3OH & \rightarrow & 3RCOOCH_3 & + & CHOH \\ | & & & & & & | \\ CH_2COOR & & & & & & CH_2OH \\ \text{[Oil / fat]} & & \text{[Methanol]} & & \text{[Methylester]} & & \text{[Glycerin]} \end{array}$$

There are a variety of fatty acids that compose vegetable oil, depending on the resource, such as rapeseed and palm. In addition, as there is no single variety of fatty acid that is ester bonded to glycerin, the composition is complex. Although the structures of the molecules are not fixed, the term BDF is used since the physical and chemical properties are similar to that of diesel. Research into BDF is currently in progress in countries such as Italy (rapeseed oil, sunflower oil), France (rapeseed oil, sunflower oil, palm oil, soybean oil), the U.S. (soybean oil) and Malaysia (palm oil).

Table 2.3.1 Comparison of properties of diesel and BDF

		Diesel	BDF in Town A			Diesel	BDF in Town A
Density (15℃)	g/cm^2	0.8299	0.8866	Carbon residue content	mass%	0.1 or less	0.05
Kinematic viscosity (40℃)	mm^2/s	1.7-2.7 or over	4.688	Sulfur content	mass%	0.20 or less	less than 0.01
Flash point (COC)	℃	45 - 50 or over	190	Heating value (cal)	kcal/kg	10,997	9,507
Pour point	℃	+5 - -30 or less	2.5	Heating value (J)	MJ/kg	46.0	39.8

[Source] Energy Policy Division, Natural Resources and Energy Department, Kansai Bureau of Economy, Trade and Industry (METI Kansai) [2002]

(2) Ethanol

Ethanol conversion technology, which uses microorganisms, has been long established in the manufacturing processes of alcoholic beverages. Relative to this, the oil shock of the 1970s triggered research and development into the production of ethanol for fuel, with Brazil promoting sugar (molasses) and the U.S. corn as the resource for ethanol production.

In the ethanol yielding reaction, 1) starch is saccharified by amylase to become glucose, 2) through many microorganisms, one glucose molecule is broken down into two pyruvic acid molecules and eventually into two ethanol molecules.

$$(C_6H_{10}O_5)_n + n\,H_2O \rightarrow n\,C_6H_{12}O_6$$

$$C_6H_{10}O_6 \rightarrow 2C_2H_5OH + 2CO_2$$

Of the progress of biotechnology in recent years, ethanol conversion using cellulosic biomass resources is drawing particular attention. In this process, ethanol is produced after the saccharification of cellulosic biomass using acid saccharification or cellulase saccharification through a fermentation process using yeasts and bacteria cultivated through genetic recombination to enable the fermentation of both hexose and pentose. Research into this process is being vigorously pursued in countries such as the U.S., and plans for industrialization are being promoted (the diagram shows an example of a current bio-ethanol production process concept).

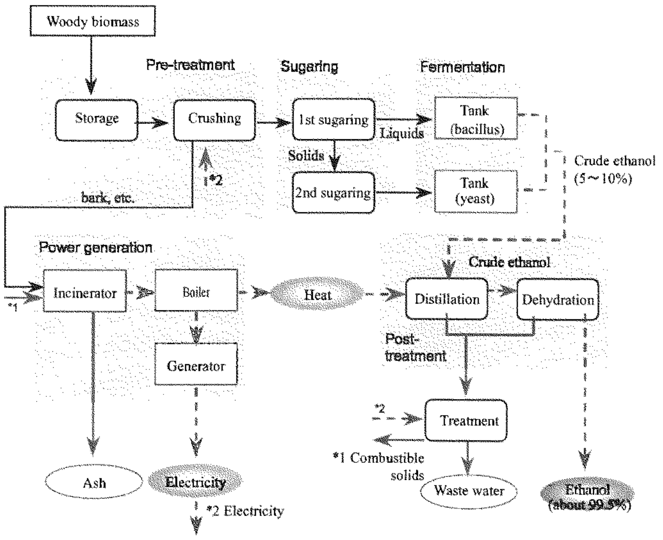


Figure 2.3.1 Example of bioethanol production process in current technology

(3) Biogas

Biogas is the final product of the CH_4 fermentation process, composed mainly of CH_4 and CO_2, and is also known as digestion gas. CH_4 fermentation is a process in which a diversity of anaerobic microorganisms degrade organic matter, and has long been in use as a method of processing effluent containing waste materials and organic impurities. As CH_4 fermentation is an anaerobic process, in comparison to an aerobic process, it does not require ventilation, and in addition, has the advantage of allowing CH_4 gas recovery. On the other hand, there are disadvantages related to the slow speed of the process, necessitating large-scale facilities. However, increased importance is now placed on the effective utilization of biomass energy, and from this perspective, instead of waste processing, the development of technology to exploit the availability of CH_4 is currently being promoted.

Biomass to which CH_4 fermentation can be applied include food waste, livestock manure, agricultural waste, and so on. CH_4 fermentation is anaerobic and progresses of its own accord in the right temperatures for degradation, pH, and in the absence of inhibitors (heavy metals such as Cr and Cu, cyan, some organics such as phenol, and NH_3). As long as these conditions are met, CH_4 gas will be generated without any particular action being required at the final processing facility.

As CH_4 fermentation progresses in stages with a diversity of anaerobic bacteria, the process is a complex system. First, the high-molecular organic substances such as proteins and carbohydrates, contained in biomass are degraded into low-molecular constitutional units such as amino acids and monosaccharides, by hydrolytic and acid producing bacteria, generating acetic acid and other organic acids. Next, the CH_4 producing bacteria, a strict anaerobe, degrades the molecules to the final product such as CH_4 and CO_2.

As CH_4 fermentation is a microbial process, it is affected by temperature. In general, although the process is separated into low temperature, medium temperature range of 30-35 degrees C and a high temperature range of 50-55 degrees C, since the degradation speed increases with fermentation temperature, high temperature fermentation is increasingly being adopted as this will lead to the downsizing of processing vats.

As CH_4 gas obtained from processes such as the above contains small amounts of substance such as H_2S, further refining may be necessary depending on usage. The main forms of energy required for the CH_4 fermentation process are heating energy required to maintain fermentation temperature, and energy required to convey the reaction mixture and pump the CH_4 gas.

2.3.2 Procedures for data collection of unit process

In relation to fuel production pathways using biomass resources as the source, in view of the fact that the scope of the reference materials and finer details concerning conditions cannot be fully understood, this study organizes and presents data that clarifies energy consumption range and CO_2 emissions range, and data typifying processes and resource/energy input, as calculation results.

In biomass production, along with the feedstock for energy conversion, byproducts are cultivated simultaneously. Specifically, energy is also consumed in the cultivation process in areas other than for the parts that can be used for energy conversion (for example, seeds from rapeseed and corn). However, as this is essential to the cultivation of the parts that can be used for energy conversion, this study treats all energy consumed as energy required for the production of the energy conversion feedstock.

Carbon ingested during the biomass production stage is treated as an assimilated amount and is given as a negative value. The given amount for assimilated carbon is a value equivalent to that of the amount generated during combustion (carbon balance zero).

Additionally, in the energy conversion process, only the heating value of the biomass resource is considered in cases where biomass is used as the in-house heat source (e.g. ethanol conversion of sugarcane), and data is created with CO_2 emissions generated from biomass resource combustion as zero.

Regarding the byproduct emissions from each process, some may be utilized as in-house energy sources or as animal feed. However, the purpose of byproducts vary depending on value (e.g. quality and cost), and although processing as waste will be necessary where the value is low, calculations in this study are based on the premise that byproducts will be disposed of.

(1) BDF

The BDF production pathway flow examined in this study are shown in Figure 2.3.2:

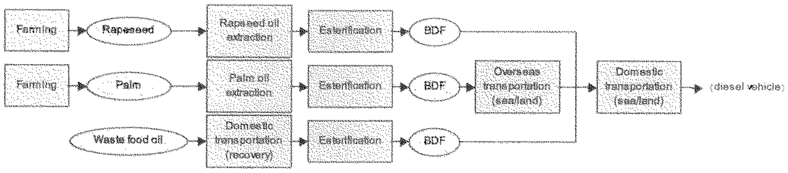


Figure 2.3.2 Pathway flow for BDF production

1) Farming

<i> Existing Study

Biomass resources used in BDF production (esterification) include oil crops such as palm, soybean, rapeseed and sunflower, and the waste food oils originating from these crops.

Energy input for palm production is considered in Fuel Policy Subcommittee (FPS) [2003].

Regarding rapeseed, European rapeseed farming data is presented in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1, and similar data for the UK is compiled in ETSU [1996].

Regarding waste food oil, from the waste materials perspective, although the production energy is beyond the sphere of the system, the Kansai Bureau of Economy, Trade and Industry [2002] report provides figures for the generation of waste food oil per household, while the Ministry of Agriculture, Forestry and Fishery (MAFF) General Food Policy Bureau – Consumption and Lifestyle Division [2001] provides figures for the generation of waste food oil per individual.

<ii> This Study

N_2O emissions from soil have been calculated using the emission factors (15.6 [kg-N_2O/t-N]) for direct emissions [Synthetic Fertilizer] given in MOE [2002-2] (p.II-79). This is based on a flux study of N_2O from fields conducted nationwide, and is an estimated value which takes crop species into consideration. Specifically, N_2O emissions from the farming process were calculated by multiplying the amount of nitrogen input to farming with this emission factor.

Regarding farming of BDF production pathway, this study considers rapeseed and palm. For rapeseed, as rapeseed production in Canada and Australia, the two major rapeseed import sources (producing countries) to Japan, is in decline, import was not assumed and the study focuses on domestic production. In addition, concerning palm, farming in Malaysia is assumed.

[Rapeseed farming]

Regarding the rapeseed farming process, as there is no detailed data for rapeseed cultivation in Japan, estimates were made from assumed fertilizer input and energy consumption values derived through hearing surveys conducted in Aomori, Japan's largest rapeseed producing region, and publications (Aomori Prefecture, Agriculture and Forestry Dept. [1994]). Regarding the production processes for fertilizer and insecticide, calculations were made using information given in Turhollow, A.F. *et al.* [1991].

[Palm farming]

Calculations for the palm farming process are based on FPS [2003]. Since palm production is mainly a manual process, energy for processes such as cultivation was assumed to be zero, and calculations were made only for energy consumption through fertilizer input.

[Waste food oil]

Regarding waste food oils, since the premise is the collection and use of oils generated as a waste product, energy consumption and GHG emissions related to waste food oil generation are ignored.

2) Transportation (Harvestry)

<i> Existing Study

Regarding palm harvesting, FPS [2003] gives the average shipping distance as 10 km.
On the other hand, regarding the collection of waste food oils, calculations in the Mitsubishi Research Institute (MRI), *et al.* [2002] (p. II.84) assume that a medium sized truck (fuel consumption 3.5 km/L) will travel an average 3 km per t of collected waste cooking oil.

<ii> This Study

Energy regarding rapeseed harvesting is treated as zero, as energy for harvesting has already been considered as a part of cultivation in the farming process. In addition, regarding palm harvest, although there a large variations depending on harvest area, energy consumption is treated as zero in this study as energy consumption related to harvesting represents only a small part of the energy consumption for the overall BDF production pathway.
Regarding the collection of waste food oils, as with MRI, *et al.* [2002], calculations were based on the assumption that a medium sized truck (fuel consumption 3.5 km/L) will travel an average 3 km per t of collected waste food oil.
In addition, regarding transportation from harvest location to BDF production facility, as it is important that conversion to BDF at the harvest location is practical and that for BDF production from high quality raw palm oil, free fatty acid is not generated, proximity between raw palm oil production facility and BDF production facility is desirable (NEDO [2003-2]), therefore the energy for transportation from harvest location to BDF production facility is treated as zero.

3) BDF Production (Oil Extraction)

<i> Existing Study

Regarding oil extraction, data related to raw oil production from rapeseed in Japan is provided in FPS [2003].

In addition, entries concerning oil extraction can be found in ETSU [1996], Shaine Tyson [1998], Sheehan, J. *et al.* [1998], Kadam, K.L. *et al.* [1999], Armstrong, A.P. *et al.* [2002], Ahlvik, P. *et al.* [2002], and EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1, and so on.

<ii> This Study

Prior studies concerning oil extraction from rapeseed give figures for overall energy input (MJ), although some are unclear as to energy type. In addition, of those that do give clear indication of energy type, many involve the use of natural gas, which cannot be assumed in relation to oil extraction from rapeseed in Japan. Therefore, this study uses data provided in ETSU [1996] (p.97, p.156-157), which uses only electricity as the energy related to oil extraction from rapeseed.

In addition, regarding palm, as the related data was unobtainable, energy consumption and GHG emissions calculations were conducted using data provided in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 (p.40), a relatively recent document regarding oil extraction from rapeseed[2]. Furthermore, NEDO [1992] was used for reference concerning palm oil yield from palm (excluding surplus material).

4) BDF Production (Refining)

<i> Existing Study

Regarding the refining process required for esterification, inventory data concerning the refining of rapeseed oil (raw oil) is provided in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 (p.40).

<ii> This Study

Regarding the refining of rapeseed oil (raw oil), data provided in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 (p.40) has been used. In addition, regarding palm oil (raw oil), as the related data was unobtainable, it was assumed to be included in the BDF production (esterification) process.

5) BDF Production (Esterification)

<i> Existing Study

In relation to the BDF production process, NEDO [2003-2] shows FS results relative to BDF production on a scale of 15,000,000 t per year. The process assumed here is the ECB Enviro Berlin AG process.

Regarding BDF production from soybean oil, information based on examples in the U.S. is compiled in Sheehan, J. *et al.* [1998]. The example given in the study is not of mechanical oil extraction but of oil extraction through the use of solvents.

Regarding rapeseed oil, EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 studies energy input for a hypothetical plant on a production scale of 20,000 t/year, using a 10,000-15,000 t/year system currently in operation in the EU for reference. It is considered in this system that materials remaining above ground after

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[2] Regarding oil expression from palm, although the use of electricity or natural gas is anticipated, as there are cases in Malaysia where oil expression is conducted manually, there may be cases where energy consumption and GHG emissions of this process are not taken into consideration.

rapeseed harvest are partly used as an energy resource and that all in-house power is provided through natural gas.
In addition, although BDF production is gradually progressing in Japan, in principle, the focus is on waste food oil. In many cases, data related to energy input is derived from materials based on hearing surveys.

<ii> This Study

[Esterification of rapeseed oil]

As existing research has considered the input of energy resources other than electricity in relation to the esterification of rapeseed oil, the following four cases were considered in this study.

Case 1) Use of rapeseed straw
Case 2) Use of natural gas
Case 3) Use of electricity + natural gas
Case 4) Use of electricity only

The cases here consider cases where electricity is purchased from the networks, and cases where in-house co-generation is conducted using rapeseed straw or natural gas to provide electricity.
In addition, regarding energy consumption and GHG emissions in the process leading to methanol production, calculations were based on relatively recent studies with natural gas as the resource, conducted by PEC [2002-2] and General Motors, *et al.* [2002], giving fuel efficiency at 67 % (worst case scenario).

[Esterification of palm oil]

Esterification of palm oil is studied in NEDO [2003-2] (p.97), and this data is also used in this study.

[Esterification of waste food oil]

Regarding processes of esterification of waste food oil already in progress in Japan, as there are only examples of electricity for energy input, in this study, the esterification of rapeseed oil (Case 4) is also applied to waste food oil.

6) Overseas Transportation (Sea/Land)

<i> Existing Study

In FPS [2003], calculations are made with distance from South-East Asia to Japan at 5,000 km (one-way) and a crude oil tanker (0.059 MJ/t-km) as the tanker.

<ii> This Study

This study also conducted calculations with distance from South-East Asia to Japan set at 5,000 km. (one-way). In addition, the tanker in this study is a 100,000 t class crude oil tanker.

7) Domestic Transportation (Sea/Land)

<i> Existing Study

In FPS [2003], calculations are made with the average domestic shipping distance (round trip) set at approximately 209 km for transportation undertaken by tank lorry from distribution base to gas station.

<ii> This Study

In this study, data related to the domestic transportation of diesel calculated in “2.1 Petroleum Based Fuel Production Pathways” has been substituted.

(2) Ethanol

The ethanol production pathway flow examined in this study are shown in Figure 2.3.3:

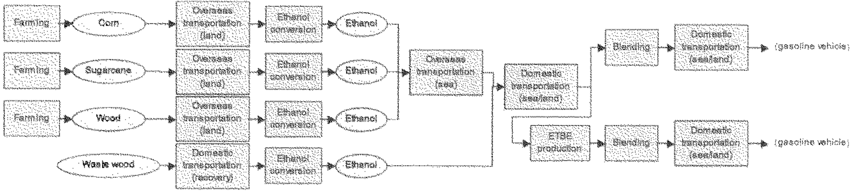
Farming
Corn
Overseas transportation (land)
Ethanol conversion
Ethanol
Farming
Sugarcane
Overseas transportation (land)
Ethanol conversion
Ethanol
Farming
Wood
Overseas transportation (land)
Ethanol conversion
Ethanol
Waste wood
Domestic transportation (recovery)
Ethanol conversion
Ethanol
Overseas transportation (sea)
Domestic transportation (sea/land)
Blending
Domestic transportation (sea/land)
(gasoline vehicle)
ETBE production
Blending
Domestic transportation (sea/land)
(gasoline vehicle)

Figure 2.3.3 Pathway flow for ethanol production

Ethanol is not supplied directly into a vehicle, but is used as a blend with gasoline or converted into ethyl tertiary butyl ether (ETBE) and then blended with gasoline. Assuming blending with current gasoline calculated in “2.1 Petroleum Based Fuel Production Pathways”, this study focuses on three fuels types; 3 % ethanol blend gasoline, 10 % ethanol blend gasoline and gasoline/ETBE blend.

1) Farming

<i> Existing Study

Regarding corn farming, the results of studies in North America have been compiled by Marland, G. *et al.* [1991], Lorenz, D. *et al.* [1995], Levelton Engineering Ltd. *et al.* [2000], Aden, A. *et al.*, and variations can be seen depending on fertilizer input and irrigation.

A report on sugarcane farming in Brazil can be found in Isaias de Carvalho Macedo [1998]. The energy for cultivation reported in the study is mainly diesel, fertilizer and insecticide, with both average and optimum data compiled in the report. Mechanization of harvesting is currently at 20%, with the report indicating future mechanization up to 50 %.

Data pertaining to fertilizer, insecticide and energy input related to cultivation is compiled in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 for wheat, and ETSU [1996] for winter wheat. In particular, wheat drying is included along with machinery fuel in data related to diesel in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1. EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 also compiles data related to sugar beet farming.

For data regarding cellulosic biomass farming, an example of hybrid poplar is compiled in Lorenz, D. *et al.* [1995]. As little fertilizer is used and there is no irrigation, energy input is low in comparison to other crops such as corn.

Regarding waste wood, as the use of waste materials generated from the demolition of houses and so on is assumed, energy input and GHG emissions are treated as zero.

<ii> This Study

[Corn farming]

As a number of reports from prior studies are available regarding corn farming, these reports were compared and data given for the maximum energy consumption case (Lorenz, D. *et al.* [1995]) and the minimum energy consumption case (Marland, G. *et al.* [1991]) has been used to calculate energy consumption and GHG emissions. This data also includes energy consumption related to fertilizer production, irrigation, corn drying, and so on.

[Sugarcane farming]

Regarding sugarcane farming, calculations for energy consumption and GHG emissions were based on average data and optimum data provided in Isaias de Carvalho Macedo [1998]. This data also includes energy for fertilizer production, insecticide and cultivation. As Isaias de Carvalho Macedo [1998] cites everything in terms of input energy, CO_2 emissions were calculated under the assumption that energy for cultivation referred mainly to cultivation related machinery, and that fuel for such would be diesel.

[Cellulosic biomass farming]

Regarding cellulosic biomass farming, energy consumption and GHG emissions calculations were based data provided in Lorenz, D. *et al.* [1995]. Ethanol conversion using cellulosic biomass has yet to be industrialized, and the results here are from trial calculations from theoretical values for hybrid poplar.

2) Overseas Transportation (Land) / Domestic Transportation (Collection)

<i> Existing Study

Energy figures for the transportation of sugarcane to ethanol conversion plants in Brazil are given in Isaias de Carvalho Macedo [1998]. A lecture given by the Nanotech Department of Mitsui & Co., Ltd., stated that transportation of sugarcane was conducted mainly by truck, and that profitability for such transportation to a distillery could only be maintained within a 50 km radius of the distillery.

<ii> This Study

In this study, calculations are based on 10 t trucks (fuel consumption 3.5 km/L) and a shipping distance of 50 km (one-way). Transportation related to domestic waste wood collection is treated in the same manner.

3) Ethanol Conversion

<i> Existing Study

Many reports in the U.S., such as Lorenz, D. *et al.* [1995] and Graboski, M.S. [2002], compile data regarding corn based ethanol conversion. There are two types of pre-treatment process that can be used in corn based ethanol production, the dry-mill process and the wet-mill process, and energy input varies depending on the pre-treatment process.

In the dry-mill process, corn is ground and water added to produce corn slurry. Once enzymes have hydrolyzed the slurry, the resulting sugar content undergoes ethanol conversion. Fermentation residue is dried and gathered, and sold on as DDGS (Distillers Dried Grains with Solubles).

In the wet-mill process, sugar content undergoes ethanol conversion once the corn oil, in particular the nutrients known as gluten feed and gluten meal, has been separated.

ETSU [1996] compiles data related to ethanol conversion using wheat as the feedstock, summarizing energy input for a system that extracts starch after the wheat has been ground and conducts ethanol conversion on a scale of approximately 140 t/d. Here, the source of in-house electricity is wheat-straw and natural gas, and the byproduct is DDGS for use as animal feed. Although similar studies have been undertaken in EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1, the scale of the plant is unclear.

Energy input related to cellulosic biomass ethanol production in the U.S. is compiled in Lorenz, D. *et al.* [1995]. This reports shows the results of a process simulation of the U.S. Arkenol, Inc. process on an industrial scale, and provides data ranging from biomass farming through to ethanol production.

Average data and optimum data is compiled in Isaias de Carvalho Macedo [1998] regarding molasses based ethanol conversion in Brazil.

Regarding ethanol conversion of cellulosic biomass, Kadam, K.L. *et al.* [1999] compiles process simulation results regarding ethanol conversion following two types of pre-treatment process, the acid degradation process currently under development and the enzymatic hydrolysis process under consideration for future development. In addition, Kadam, K.L. [2000] conducts a similar study into the ethanol conversion of bagasse in India. These studies assume a production scale of 800 t/d.

In addition, EUCAR, CONCAWE, & JRC/IES [2003] Appendix 1 also compiles data regarding the ethanol conversion of sugar beet fibre remaining after juicing.

<ii> This Study

[Ethanol conversion from corn]

Regarding the ethanol conversion of corn, there are differences in energy consumption depending on whether the corn degradation pre-treatment is conducted using the dry-mill or the wet-mill process. In this study, following consideration and comparison of Levelton Engineering Ltd. *et al.* [2000] (Canada) and Graboski, M.S. [2002] (U.S.) for the dry-mill process, and Marland, G. *et al.* [1991] and Graboski, M.S. [2002] (U.S.) for the wet-mill process, energy consumption and GHG emissions were calculated based on data provided for maximum energy consumption (Marland, G. *et al.* [1991]) and minimum energy consumption (Levelton Engineering Ltd. *et al.* [2000]).

[Ethanol conversion from sugarcane]

Regarding the ethanol conversion of sugarcane, calculations for energy consumption and GHG emissions were based on average data and optimum data provided in Isaias de Carvalho Macedo [1998].
Regarding the ethanol conversion of sugarcane, there are many cases where bagasse (sugarcane residue) combustion is used to power steam turbines for power generation. When calculating GHG emissions in this study, GHG emissions for purchased power equivalent to power generated through bagasse combustion were also studied for comparison purposes. Calculations here for total bagasse generation are based on material balance data given in Japan Energy Research Center [2002] (p.102).

[Ethanol conversion from cellulosic biomass]

Regarding the ethanol conversion of cellulosic biomass, the process using acid as a pre-treatment for biomass saccharification, has been included.
Regarding the ethanol conversion of cellulosic biomass, energy consumption and GHG emissions calculations are based on data provided in Kadam, K.L. *et al.* [1999] (p.34). The calculations in this data separate cellulosic materials into shrubs, softwoods and rice straw, of which this study uses data for shrubs and softwoods.
Regarding the ethanol conversion of waste wood, data related to softwoods with comparatively similar compositions is applied, and conversion into heating value in Japan and re-calculation was conducted only in relation to natural gas consumption.

4) Overseas Transportation (Sea)

<i> Existing Study

In FPS [2003], calculations are made with shipping distance from India to Japan at 8,900 km (one-way) and a crude oil tanker (0.068 MJ/t-km) as the tanker.

<ii> This Study

In this study, calculations are made under the assumption of transportation to Japan of, corn from the U.S. (Los Angeles: 4,849 miles), sugarcane from Brazil (Rio de Janeiro: 11,768 miles) and cellulosic biomass from Malaysia (Bintulu: 2,511 miles). In addition, assuming that the tanker used will be the same vessel as used for methanol, details given in NEDO [2001-3] for capacity of methanol vessels, and speed and fuel consumption for GTL vessels was substituted.

5) Domestic Transportation (Sea/Land)

<i> Existing Study

In FPS [2003], calculations are made with the average domestic shipping distance (round trip) set at approximately 209 km for transportation undertaken by tank lorry from distribution base to gas station.

<ii> This Study

In this study, data calculated in "2.1 Petroleum Based Fuel Production Pathways" in relation to the domestic transportation of gasoline has been substituted.

6) ETBE Production

Regarding the ETBE production from ethanol process, energy consumption calculations are based on Kadam, K.L. *et al.* [1999] (p.38) and "Regarding ETBE" found at the MOE website (http://www.env.go.jp/earth/ondanka/renewable/03/mat_03.pdf).

7) Blending

Energy consumption and GHG emissions of the blending process have been omitted, as the information required to create inventory data was unobtainable.

(3) Biogas (Methane Gas)

The CH_4 fermentation pathway flow examined in this study are shown in Figure 2.3.4:

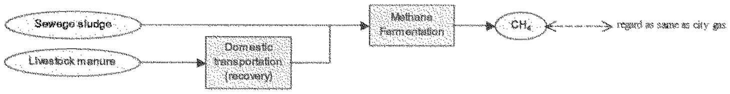
Sewage sludge
Livestock manure
Domestic transportation (recovery)
Methane Fermentation
CH_4
regard as same as city gas

Figure 2.3.4 Pathway flow for CH_4 fermentation

1) Domestic Transportation (Collection)

CH_4 fermentation feedstock in Japan focuses on sewage sludge and livestock manure, and very little focus is placed on food waste and others.

Regarding sewage sludge, the main form of transportation is pipeline from the sewage plant, with some septic tank sludge shipped by sewage vacuum car. In addition, regarding livestock manure, in many cases the manure is accumulated in tanks at the farm and then shipped in by overland transportation (e.g. light trucks) owned by the farms. Therefore, calculations in this study are based on 2 t trucks (fuel: gasoline, fuel consumption: 6.0 km/L) and a shipping distance of 10 km (one-way).

2) CH_4 Fermentation

<i> Existing Study

The operational data for the system in Yagi Town, Kyoto Prefecture, in which digestive gas obtained through the CH_4 fermentation processing of livestock manure and bean curd lees is used for gas engine power generation, is shown in Ogawa *et al.* [2003].

The Central Purification Center (CPC) of Nagaoka-City, Niigata Prefecture, supplies digestive gas obtained through the CH_4 fermentation of sewage sludge to city gas holders.

<ii> This Study

Calculations are made in this study for energy consumption and GHG emissions in relation to the CH_4 fermentation processes of the previously mentioned Yagi system detailed in Ogawa *et al.* [2003] and the Nagaoka CPC example.

In recent years, although many small-scale CH_4 fermentation facilities have been established, the utilization of these in terms of CH_4 fermentation for automotive fuel production is considered difficult. On the other hand, the Yagi Bio-Ecology Center covered in this study is the most famous and largest livestock manure CH_4 fermentation facility in Japan.

In addition, the Nagaoka CPC is most representative of biogas generation through CH_4 fermentation for use as a substitute for city gas. In this study, energy consumption and GHG emissions calculations were based on data obtained through a hearing survey conducted in relation to the Nagaoka CPC.

3) Distribution

Regarding distribution to city gas holders, energy consumption and GHG emissions calculations were based on data obtained through a hearing survey conducted in relation to the Nagaoka CPC.

2.3.3 Calculation results

Regarding the fuel production pathways from biomass resources, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ BDF are shown in Table 2.3.2 (energy consumption), Table 2.3.3 (GHG emissions) and Table 2.3.4 (energy efficiency).

The results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ ethanol are shown in Table 2.3.5 (energy consumption), Table 2.3.6 (GHG emissions) and Table 2.3.7 (energy efficiency).

The results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ biogas are shown in Table 2.3.8 (energy consumption), Table 2.3.9 (GHG emissions) and Table 2.3.10 (energy efficiency).

Table 2.3.2 WTT energy consumption of BDF production pathways [MJ/MJ]

	BDF from rapeseed					BDF from palm		BDF from waste food oil
	Straw	Natural gas	Electricity + Natural gas	Electricity	CO_2 emission maximum case	Including oil extraction	Excluding oil extraction	
Farming	0.107	0.107	0.110	0.113	0.153	0.128	0.128	-
Recovery	-	-	-	-	-	-	-	0.001
Oil extraction	0.223	0.223	0.229	0.236	0.223	0.068	0.000	-
Oil refining	0.010	0.010	0.011	0.011	0.010	↓	↓	↓
Esterification	0.271	0.241	0.101	0.055	0.241	0.076	0.076	0.055
Overseas transportation	-	-	-	-	-	0.011	0.011	-
Domestic transportation	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Total	0.616	0.586	0.456	0.420	0.633	0.289	0.220	0.061

Table 2.3.3 WTT GHG emissions of BDF production pathways [g eq-CO_2/MJ]

	BDF from rapeseed					BDF from palm		BDF from waste food oil
	Straw	Natural gas	Electricity + Natural gas	Electricity	CO_2 emission maximum case	Including oil extraction	Excluding oil extraction	
Farming	13.9	13.9	14.3	14.8	13.6	14.4	14.4	-
Recovery	-	-	-	-	-	-	-	0.1
Oil extraction	8.9	8.9	9.1	9.4	8.9	3.9	0.0	-
Oil refining	0.6	0.6	0.6	0.6	0.6	↓	↓	↓
Esterification	1.4	13.3	5.2	2.4	13.3	3.7	3.7	2.4
Overseas transportation	-	-	-	-	-	0.8	0.8	-
Domestic transportation	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	25.2	37.1	29.7	27.6	36.8	23.2	19.4	2.9
Fixed CO_2	△76.2	△76.2	△76.2	△76.2	△76.2	△76.2	△76.2	△76.2

Table 2.3.4 WTT energy efficiency of BDF production pathways (LHV)

	BDF from rapeseed					BDF from palm		BDF from waste food oil
	Straw	Natural gas	Electricity + Natural gas	Electricity	CO_2 emission maximum case	Including oil extraction	Excluding oil extraction	
Farming	↓	↓	↓	↓	↓	↓	↓	-
Recovery	↓	↓	↓	↓	↓	↓	↓	↓
Oil extraction	↓	↓	↓	↓	↓	↓	↓	-
Oil refining	↓	↓	↓	↓	↓	↓	↓	↓
Esterification	0.738	0.756	0.853	0.896	0.713	0.932	0.985	0.994
Overseas transportation	-	-	-	-	-	0.989	0.989	-
Domestic transportation	0.994	0.994	0.994	0.994	0.994	0.994	0.994	0.994
Total	0.734	0.751	0.848	0.891	0.709	0.916	0.969	0.988

Table 2.3.5 WTT energy consumption of ethanol production pathways [MJ/MJ]

	Ethanol from corn		Ethanol from sugarcane (bagasse utilization)		Ethanol from sugarcane (power grid utilization)		Ethanol from foreign wood		Ethanol from domestic waste wood
	(worst)	(best)	(average)	(best)	(average)	(best)	(worst)	(best)	
Farming	0.328	0.258	0.076	0.067	0.076	0.067	0.280	0.105	-
Overseas transportation (land)	0.013	0.012	↑	↑	↑	↑	0.046	0.017	-
Recovery	-	-	-	-	-	-	-	-	0.017
Ethanol production	0.648	0.611	0.843	0.748	0.081	0.072	2.307	1.366	1.634
Overseas transportation (sea)	0.057	0.057	0.133	0.133	0.133	0.133	0.031	0.031	-
Domestic transportation	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Total	1.055	0.946	1.060	0.957	0.299	0.281	2.673	1.527	1.660

Table 2.3.6 WTT GHG emissions of ethanol production pathways [g eq-CO_2/MJ]

	Ethanol from corn		Ethanol from sugarcane (bagasse utilization)		Ethanol from sugarcane (power grid utilization)		Ethanol from foreign wood		Ethanol from domestic waste wood
	(worst)	(best)	(average)	(best)	(average)	(best)	(worst)	(best)	
Farming	32.14	28.23	6.94	6.04	6.94	6.04	25.15	9.40	-
Overseas transportation (land)	0.96	0.89	↑	↑	↑	↑	3.39	1.27	-
Recovery	-	-	-	-	-	-	-	-	1.27
Ethanol production	55.06	34.82	0.00	0.00	1.52	1.35	143.49	84.91	93.31
Overseas transportation (sea)	4.39	4.39	10.28	10.28	10.28	10.28	2.40	2.40	-
Domestic transportation	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
Total	93.21	68.98	17.87	16.97	19.39	18.32	175.09	98.64	95.24
Fixed CO_2	△71.28	△71.28	△71.28	△71.28	△71.28	△71.28	△71.28	△71.28	△71.28

Table 2.3.7 WTT energy efficiency of ethanol production pathways (LHV)

	Ethanol from corn		Ethanol from sugarcane (bagasse utilization)		Ethanol from sugarcane (power grid utilization)		Ethanol from foreign wood		Ethanol from domestic waste wood
	(worst)	(best)	(average)	(best)	(average)	(best)	(worst)	(best)	
Farming	↓	↓	↓	↓	↓	↓	↓	↓	↓
Overseas transportation (land)	↓	↓	↓	↓	↓	↓	↓	↓	↓
Recovery	-	-	-	-	-	-	-	-	↓
Ethanol production	0.588	0.590	0.533	0.562	0.924	0.931	0.282	0.408	0.377
Overseas transportation (sea)	0.946	0.946	0.882	0.882	0.882	0.882	0.970	0.970	-
Domestic transportation	0.991	0.991	0.991	0.991	0.991	0.991	0.991	0.991	0.991
Total	0.552	0.554	0.466	0.492	0.809	0.815	0.271	0.392	0.374

Table 2.3.8 WTT energy consumption of CH_4 gas production pathways [MJ/MJ]

	Livestock manure	Sewage sludge
Recovery	0.054	-
CH_4 fermentation	0.521	0.584
Distribution	0.194	0.194
Fueling to vehicles	0.046	0.046
Total	0.814	0.823

Table 2.3.9 WTT GHG emissions of CH_4 gas production pathways [g eq-CO_2/MJ]

	Livestock manure	Sewage sludge
Recovery	4.0	-
CH_4 fermentation	15.0	16.8
Distribution	5.4	5.4
Fueling to vehicles	1.8	1.8
Total	26.3	24.1
Fixed CO_2	△ 57.0	△ 57.0

Table 2.3.10 WTT energy efficiency of CH_4 fermentation pathways (LHV)

	Livestock manure	Sewage sludge
Recovery	↓	-
CH_4 fermentation	0.835	0.861
Distribution	0.951	0.951
Fueling to vehicles	0.983	0.983
Total	0.780	0.804

2.4 Synthetic Fuel Production Pathways

2.4.1 Abstract

Gas-to-Liquid (GTL) technology, which converts natural gas to liquid fuel, has recently become the focus of attention. The background to this is that upstream there is an abundance of undeveloped gas fields and an increased need for development in gas producing countries, while midstream there is improved economic efficiency due to improved GTL technology, and downstream there is an increased need for clean fuels due to stricter environmental regulations (Suzuki [2001]).

Methods for the conversion of natural gas into liquid fuel can be divided into two broad categories, the indirect method, in which the gas is first converted into a highly reactive syngas (a mixture of CO and hydrogen) and then converted into FT synthetic oil, DME, methanol and so on, and the direct method, in which natural gas is converted directly to methanol and so on, without requiring initial conversion to syngas. Although the direct method was heavily researched in the 1980s in order to find a method of reducing costs related to the syngas production process, there were technical difficulties concerning the inhibition of carbon dioxide gas generation as a side reaction, and although research is still undertaken at universities and others, there is no current industry level research (Suzuki [2001]).

The synthetic fuel production process consists of three processes, the syngas production process, the FT synthesis (DME synthesis, methanol synthesis) process and the hydrocracking/product refining process.

(1) Syngas Production from Natural Gas

Reforming processes are applied to produce syngas from natural gas; these include the following four methods:

- Steam Reforming (SMR)
- Steam / CO_2 Reforming
- Autothermal Reforming (ATR)
- Partial Oxidation (POX)

The H_2/CO molar ratio for the composition of syngas generated from the above four methods is different for each gas (See Figure 2.4.1).

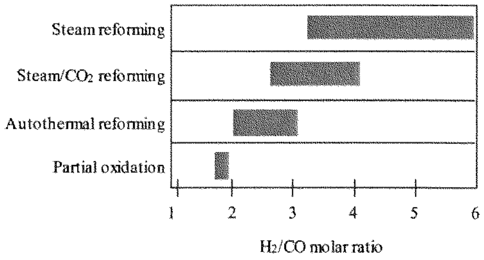

Figure 2.4.1 Relation between syngas production process and H_2/CO molar ratio
([Source] Asaoka, *et.al* [2001])

1) Steam Reforming (SMR)

This process has the greatest track record. Generally, this method uses a reaction between the hydrocarbons in the feedstock and steam, in the presence of a nickel catalyst, at 600-850 degrees C and 2-3 MPa. The chemical formula is as follows.

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

As this is a strong endothermic reaction, the method is characterized by the need for the heat source (Sato [2001]).

2) Steam / CO_2 Reforming

This method combines the steam reforming reaction and the CO_2 reforming reaction, using steam and CO_2 as oxidizing agents to convert natural gas into syngas. Although the optimum H_2/CO ratio of syngas for a FT reaction is 2, as steam reforming of natural gas generates a H_2/CO ratio greater than 3, a CO_2 reformer is added to allow adjustment through CO_2 reforming. JNOC is also conducting research and development of this process, which allows CO_2 contained in the feedstock gas to be utilized along with the natural gas as part of the feedstock without requiring removal.

3) Autothermal Reforming (ATR)

This reforming method combines the partial oxidization process (an exothermic reaction) with the steam reforming process (an endothermic reaction) in order to improve thermal efficiency, while maintaining thermal balance through one or two reactors. Autothermal reforming uses pure oxygen. As with the steam reforming process, a nickel catalyst is used (Sato [2001]).

4) Partial Oxidation (POX)

By providing less oxygen than would be required for complete combustion in the absence of a catalyst, this method causes incomplete combustion and uses the heat obtained from the exothermal reaction for gasification. As no catalyst is used, no problems occur even if impurities are present in the feedstock. This method can be applied to many hydrocarbons other than natural gas, such as coal, heavy oil and biomass.
Pure oxygen or air is used as the oxidizing agent. The chemical reaction formula is as follows (Sato [2001]).

$$CH_4 + (1/2)\,O_2 \rightarrow CO + 2H_2$$

(2) FT Synthesis, DME Synthesis and Methanol Synthesis

Possible processes following on from syngas include FT synthesis, DME synthesis and methanol synthesis. However, as each process has its own suitable H_2/CO molar ratio[3], a process combined with a reforming process to attain the suitable H_2/CO molar ratio is desirable.

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[3] Although for methanol synthesis the ratio is (H2 - CO_2) / (CO + CO_2), this shall also be cited henceforth as H_2/CO ratio

- FT synthesis	: $2H_2 + CO \rightarrow (1/n)(CH_2)_n + H_2O$	+ 167 kJ/mol
- DME synthesis (direct)	: $3CO + 3H_2 \rightarrow CH_3OCH_3 + CO_2$	+ 244.9 kJ/mol
- Methanol synthesis	: $CO + 2H_2 \rightarrow CH_3OH$	+ 90 kJ/mol
	$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$	+ 49 kJ/mol

The reaction formula for each is shown below. As is apparent from the reaction formula, the H_2/CO molar ratio suitable for FT synthesis and methanol synthesis is 2, and the ratio suitable for DME synthesis is 1. Therefore, for FT synthesis and methanol synthesis, the reforming processes that attain a H_2/CO molar ratio in the region of 2, as shown in Fig 2.4.1, namely the autothermal reforming process and the partial oxidization process are suitable. Although a FT synthesis process using Steam/CO_2 reforming has recently been developed, as this reforming process is able to attain H_2/CO molar ratio=2, it is also extremely suited to FT synthesis.

* FT synthesis, DME synthesis, methanol synthesis through the gasification of coal or biomass

Where gasification of coal or biomass is conducted, a wet gas cleaning process is first applied, as substances such as tar are present in the syngas. Afterwards, depending on the CH_4 concentration present in the syngas, the gas is passed through a reformer and then on to a process to attain the suitable H_2/CO molar ratio for the subsequent stages. If the H_2/CO molar ratio is greater than required at this point, surplus H_2 is generated causing deterioration in efficiency.

As with the reforming of natural gas, when coal is gasified a syngas containing H_2 and CO is generated, but as the hydrogen content in coal is low the H_2/CO molar ratio of the gas is $H_2/CO \leqq 1$.

With the gasification of biomass, the composition of the generated syngas varies depending on the type of gasification furnace (furnace shape, different amounts of steam, oxygen/air input during gasification). H_2/CO molar ratios can be either $H_2/CO \leqq 1$ or $H_2/CO \geqq 1$.

As FT synthesis and methanol synthesis require a syngas with H_2/CO molar ratio=2, for syngas with H_2/CO molar ratio $\leqq 2$, the following shift reaction is used to adjust ratio to H_2/CO molar ratio=2.

$$\text{Shift reaction : } CO + H_2O \leftrightarrow CO_2 + H_2$$

An example of biomass gasification including CH_4 reforming and FT synthesis process flow is shown in Figure 2.4.2.

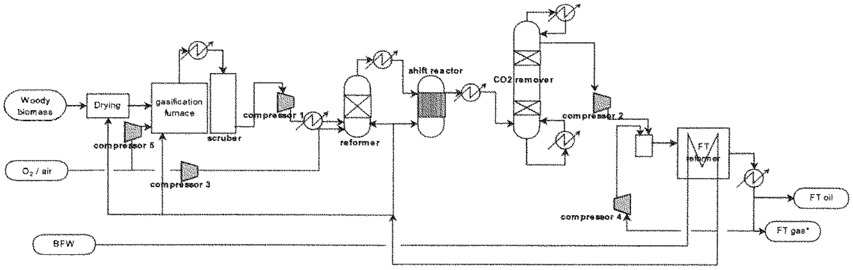

Figure 2.4.2 Process flow of biomass gasification and FT synthesis

(3) Hydrocracking of Hydrocarbons

Although, a range of products such as naphtha, kerosene and diesel can be derived from FT synthesis, the principal constituent of these is normal paraffin with a variety of carbon chains. In this process, each product is obtained through distillation following the hydrocracking of hydrocarbons obtained through FT synthesis. The principal qualities and characteristics of synthetic fuels are shown in Table 2.4.1 and Table 2.4.2.

Table 2.4.1 The principal qualities of synthetic fuels

			FT Diesel		Methanol	DME
			Sasol SSPD Diesel	Shell SMDS Diesel	CH_3OH	C_2H_6O
Molecular weight					32.04	46.07
Composition ratio	C	wt%	84.9	84.91	37.5	52.2
	H	wt%	15.1	14.97	12.6	13.1
	N	wt%		0.67		
	O	wt%	0	0	49.9	34.7
Density	15/15℃	kg/L	0.7698	0.7845	0.796	0.667
	0℃, 1atm	kg/m^3				2.05
Freezing point		℃			-97.5	
Boiling point		℃	159 - 352	210 - 338	65	-25
Vapor pressure	@38℃	kPa			32	
	@38℃	Psi			4.6	
Specific heat		kJ/ (kg-k)			2.5	2.99
Kinematic viscosity	@20℃	mPa-s			0.59	< 1
	@20℃	CSt			0.74	
	@40℃	CSt	2.08	3.57		
Water solubility	@21℃	Moisture vol%			100	
Electrical conductivity		mhos/cm			$4.4 * 10^{-7}$	
Latent heat of evapolation		kJ/kg			1,178	467.13
Higher heating value		MJ/kg	46.7	47.2	22.7	31.7
		MJ/L	35.9	37.0	18.1	21.1
Lower heating value		MJ/kg		44.0	19.7	28.8
		MJ/L		34.5	15.8	19.2
Flash point		℃	59	72	11	
Auto ignition temperature		℃			464	235
Combustion limit	Lower limit	vol%			7.3	3.4
	Upper limit	vol%			36.0	18.6
Theoretical air/fuel ratio					6.45	9.0
Velocity of diffusion flame		m/s			2 - 4	0.54
Octane number	RON				108.7	
	MON				88.6	
Cethane number			> 74.8	> 74		55 - 60
Source			Myburgh, *et al* [2000]	Norton, *et al.* [1998]	Bechtold [1997] Bosch [2000] EIA[1994]	Kajitani, *et al.* [1998] Bosch [2000]

Table 2.4.2 Properties of synthetic fuels

([Source] 1):Suzuki [2001], 2):Nakamura [2002], 3):PEC [2002-1], 4):JHFC website)

	Advantage	Disadvantage
FT diesel	· No need to develop new infrastructure and technology to be used, since its property is almost the same as petroleum-based diesel (As with other FT synthetic oils). 1) · Easily comply with quality standard of automobile diesel regulation due to its property of high cetane number and low aromatic content. 1) · Experience as commercially operated plants. 2) · Also valuable as a blending material of petroleum products. 3)	· Could worsen fuel efficiency because its density is relatively low. 1) · Poor lubrication due to its low sulfur and aroma contents, while low expansivity of seal due to its high paraffin with low aroma content. 3)
FT kerosene	· Superior in combustion quality due to its low sulfur content and high smoke point. 3) · Has a potential to be used as a fuel for household fuel cell besides an alternative of kerosene. 3) · Expected to be used as an aviation fuel (in South Africa, a mixed fuel of FT kerosene and petroleum-based jet fuel has been utilized). 3)	· The existing petroleum-based kerosene is sufficient in quality, so the issue is how much degree of premium it would be able to gain. 2)
FT naphtha	· Suitable for petrochemical naphtha as a feedstock for ethylene degradation due to its high paraffin content. 3) · Expected as a fuel for fuel cell vehicles due to its few sulfur and aroma contents. 3)	· If used at conventional internal combustion engine for gasoline, its low octane number needs to be increased by means such as alkylation. 2)
DME	· Similar property to LPG, so that infrastructure for LPG would be available. 2) · R&D has been underway to use it as a substitute fuel of diesel (fuel for diesel engine) besides LPG substitute. 2)	· Used for a limited purpose such as aerosol propellant as the CFC substitute so far, so the market is quite small. 2) · Its properties as a fuel, such as combustion quality, have not been sufficiently figured out. 2) · Infrastructure building and technology developments are necessary in order to use it as a fuel 2) · There are other issues to be solved such as production specification as a fuel, safety recognition, establishment of standard for use. 2)
Methanol	· Methanol vehicle is classified as low emission vehicles in Japan. 2) · For the use of a fuel for fuel cell vehicles, it can be reformulated in lower reaction temperature in comparison with other fuels. 4)	· One of the toxic agents designated by "Poisonous and Deleterious Substances Control Law". 2) · If used as automobile fuel, fuel efficiency tends to get worse because of its low heating value, although its octane number is high. 2) · Unsuitable for diesel engine due to its low cetane number. 2)

2.4.2 Procedures for data collection of unit process

The synthetic fuel production pathway flow examined in this study is shown in Figure 2.4.3. Of these pathways, this study acquired prior studies related to FT synthetic oil, DME, methanol production from natural gas, FT synthetic oil production from coal, FT synthetic oil, DME, methanol production from biomass. Prior studies related to other pathways, specifically DME and methanol production from coal, could not be acquired. Consequently, this study has attempted to make estimates for these pathways. Specifically, in relation to all synthetic fuel production pathways, including these pathways, conditions were set for a particular process, and energy efficiency estimates were made according to those conditions. Conditions set for the estimates and the estimates are shown in "(10) Energy Efficiency Estimates" at the end of this section.

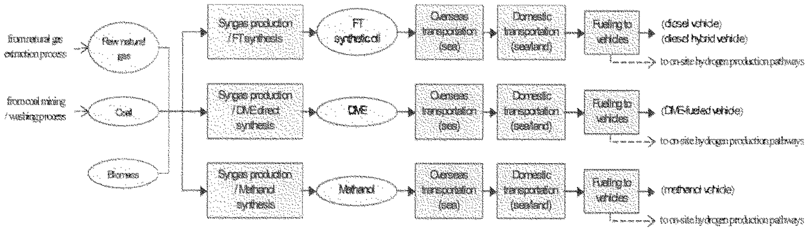
from natural gas extraction process
Raw natural gas
from coal mining / washing process
Coal
Biomass
Syngas production / FT synthesis
FT synthetic oil
Syngas production / DME direct synthesis
DME
Syngas production / Methanol synthesis
Methanol
Overseas transportation (sea)
Domestic transportation (sea/land)
Fueling to vehicles
(diesel vehicle)
(diesel hybrid vehicle)
(DME-fueled vehicle)
(methanol vehicle)
to on-site hydrogen production pathways

Figure 2.4.3 Pathway flow for synthetic fuels production

(1) FT Synthetic Oil Production Pathway from Natural Gas

<i> Existing Study

Table 2.4.3 shows data calculated in prior studies. As the range of fuel types studied varies with each report, fuel types are also clearly indicated.

Table 2.4.3 Energy efficiencies and carbon efficiencies regarding natural gas based FT synthetic oil production pathways in existing studies

Reference	Feedstock	Product	Energy efficiency or energy consumption	CO_2 emission or carbon efficiency	Cogeneration, etc.
Wang, M.Q. et al. [1999] (Argonne National Lab.)	Natural gas	FT diesel	66 %	76 %	Energy efficiency takes into account the Btu in steam
	Natural gas	FT diesel	49 %	76 %	Energy efficiency does not take into account the Btu in steam
	Natural gas	FT diesel	57 %	73 %	Design does not include steam or electricity export.
	Flared gas	FT diesel	55 %	73 %	Flared gas as feedstock. No electricity cogeneration. Incremental.
	Flared gas	FT diesel	57 %	73 %	Flared gas as feedstock. No electricity cogeneration. Leap-forward.
Marano, J.J et al.[2001] (E^2S, LLC)	Natural gas (Pipeline)	FT synthetic oil	59.1 %	57 %	With conventional product upgrading.
	Associated gas	FT synthetic oil	57.3 %	39.3 %	Associated gas as feedstock.
	Associated gas	FT synthetic oil	57.1 %	39.2 %	Associated gas as feedstock. Once-through power generation.
Argonne National Lab. [2001]	Natural gas	FT diesel, naphtha	61 - 65 %	75 - 85 %	Without steam or electricity export.
	Natural gas	FT diesel, naphtha	53 - 57 %	75 - 85 %	Excluding energy in co-products.
Ahlvik, P. et al.[2001] (Ecotraffic)	Natural gas	FT synthetic oil	57 %		
Wang, M.Q.[2001] (Argonne National Lab.)	Natural gas	FT diesel	62 %	78.3 %	Mossgas Design. Standalone.
	Natural gas	FT diesel	54 %	68.4 %	Rentech Design. Standalone.
	Natural gas	FT diesel	49.6 %	68.4 %	Rentech Design. With electricity cogeneration.
	Natural gas	FT diesel	57 %	72 %	Syntroleum Design. Standalone.
	Natural gas	FT diesel	49 %	72 %	Syntroleum Design. With steam cogeneration.
	Flared gas	FT diesel	57 %	65 %	Flared gas as feedstock. Syntroleum Design. Standalone.
PEC[2002-2]	Natural gas	FT diesel	49 - 66 %	1,370 - 2,780 g-CO_2/kg-FTD	
GM, et al. [2002]	Natural gas	FT diesel	61 - 65 %	15.8 - 21.5 g-CO_2/MJ-FTD	
	Natural gas	FT naphtha	61 - 65 %	17.3 - 23.0 g-CO_2/MJ-FTN	
Shell Gas & Power [2002]	Natural gas	FT synthetic oil	60 - 65 %	80 - 82 %	SMDS (Shell Middle Distillate Synthesis)

Data given in Bechtel Corporation [1998] has been used to calculate some of the data given in Marano, J.J *et al.* [2001]. In addition, Beer, T., *et al.* [2001] (p.128) adopts values for fuel efficiency (taking calorific value of steam into account) and carbon efficiency (for FT diesel) as given in Wang, M.Q., *et al.* [1999] (p.34). PricewaterhouseCoopers [2003] was released in May 2003 as the final report of a study on SMDS (Shell Middle Distillate Synthesis) technology, developed by Shell. Shell Gas & Power [2002] and some other reports are thought to be publications generated by this study.

<ii> This Study

In this study, energy consumption and GHG emissions calculations for the FT synthetic oil production from natural gas process are based on PricewaterhouseCoopers [2003], which focuses on new technologies and provides comparatively detailed data. As the report assumes a SMDS plant in the Middle East with unit heating value for natural gas feedstock at 43.2 MJ/kg, this study also uses this value. In addition, as the report also implements load distribution through weight, this study also follows suit.

(2) DME Production Pathway from Natural Gas

<i> Existing Study

Table 2.4.4 shows data calculated in prior studies.

Table 2.4.4 Energy efficiencies and carbon efficiencies regarding natural gas based DME production pathways in existing studies

Reference	Feedstock	Product	Energy efficiency or energy consumption	CO_2 emission or carbon efficiency	Cogeneration, etc.
Hansen, J. B. et al.[1995] (Haldor Topsøe)	Natural gas	DME		0.44 t-CO_2/t-DME	
Wang, M.Q. et al.[1999] (Argonne National Lab.)	Natural gas	DME	69 %	0.446 t-CO_2/t-DME	No electricity cogeneration, incremental
	Natural gas	DME	70 %	0.446 t-CO_2/t-DME	No electricity cogeneration, leap-forward
	Flared gas	DME	68 %	0.446 t-CO_2/t-DME	Flared gas as feedstock. No electricity cogeneration, incremental
	Flared gas	DME	69 %	0.446 t-CO_2/t-DME	Flared gas as feedstock. No electricity cogeneration, leap-forward
NEDO[2001-3]	Natural gas	DME	71 %	0.112 g-C/10kcal	Natural gas input : 1,114 Nm^3 / t-DME
Haldor Topsøe[2001]	Natural gas	DME	71.2 %	355 kg-CO_2/t-DME 12.3 g-CO_2/MJ-DME	
Ahlvik, P. et al.[2001] (Ecotraffic)	Natural gas	DME	74 %		

Of the above prior studies, the report of a study conducted by Denmark's Haldor Topsøe A/S into the company's own DME direct synthesis technology (Haldor Topsøe [2001]), provides specific input/output data related to the entire plant based on actual measurements, although it does not go into analysis of each individual process (see Figure.2.4.4).

<ii> This Study

For calculation purposes, this study uses data given in Haldor Topsøe [2001] for reference, as the basis for calculation is comparatively clear (see Figure.2.4.4).

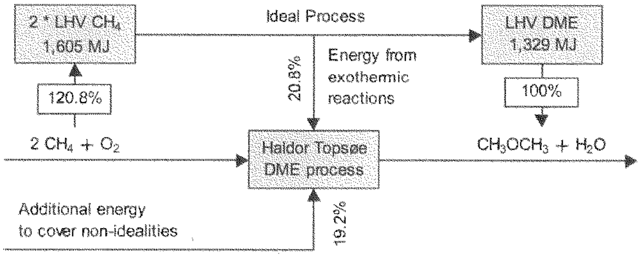

Figure 2.4.4 DME direct synthesis process by Haldor Topsøe

(3) Methanol Production Pathway from Natural Gas

<i> Existing Study

Table 2.4.5 shows data calculated in prior studies.

Table 2.4.5 Energy efficiencies and carbon efficiencies regarding natural gas based methanol production pathways in existing studies

Reference	Feedstock	Product	Energy efficiency or energy consumption	CO_2 emission or carbon efficiency	Cogeneration, etc.
IAE [1990]	Natural gas	Methanol	7.1 $*10^6$ kcal/t-MeOH	315.8 kg-CO_2/t-MeOH	Energy cosumption includes energy as feedstock.
Wang, M.Q. et al.[1999] (Argonne National Lab.)	Natural gas	Methanol	67 %		Incremental.
	Natural gas	Methanol	70 %		Leap-forward
	Flared gas	Methanol	65 %	65 %	Incremental.
	Flared gas	Methanol	67 %	67 %	Leap-forward
Argonne National Lab. [2001]	Natural gas	Methanol	67.5 %		Without steam or electricity export.
	Natural gas	Methanol	64 %		Excluding energy in co-products.
Ahlvik, P. et al.[2001] (Ecotraffic)	Natural (hydrogen-rich)	Methanol	70 %	90 %	
PEC[2002-2]	Natural gas	Methanol	67 - 70 %	710 - 820 g-CO_2/kg-MeOH	
GM, et al. [2002]	Natural gas	Methanol	67.3 - 69.4 %	12.4 - 14.9 g-CO_2/MJ-MeOH	

<ii> This Study

Unlike FT synthetic oil and DME, for the methanol production from natural gas process, there is no data with a clear basis for calculation. Consequently, in this study, energy consumption and GHG emissions for the methanol production from natural gas process were calculated for two cases, from worst (67%) and optimum (70%) fuel efficiency figures given in PEC [2002-2] and General Motors, *et al.* [2002]. Furthermore, CO_2 emissions calculations were made according to the method used in IAE [1990]. Specifically, according to the following procedure.

1) Calculation of carbon content in natural gas used for feedstock and for fuel
2) Calculation of carbon content in the produced methanol product
3) Difference in carbon content converted to CO_2 weight, result given as CO_2 emissions

However, although IAE [1990] subtracts associated CO_2 from the CO_2 emissions calculated in this manner and notes associated CO_2 separately, this study stops at figures for CO_2 emissions inclusive of associated CO_2. In addition, methanol heating values and carbon content (%) are as given in Table 2.4.1 and ANRE [1992] was used as reference for properties of natural gas used as feedstock and fuel. Regarding natural gas producing regions, although places indicated in PEC [2002-1] (p.119) may be considered such as Malaysia, Indonesia, Australia, Iran and Qatar, where plant construction is planned, this study uses simple averages derived from data regarding three countries (Malaysia, Indonesia (Badak), Australia) mentioned in ANRE [1992].

(4) FT Synthetic Oil Production Pathway from Coal

<i> Existing Study

Table 2.4.6 shows data calculated in prior studies. Regarding the FT synthetic oil production from coal process, Marano, J.J *et al.*[2001] calculates fuel efficiency and carbon efficiency for several cases according to coal producing region and production technology. These calculations are based on data given in Bechtel Corporation [1998].

Table 2.4.6 Energy efficiencies and carbon efficiencies regarding coal based FT systhetic oil production pathways in existing studies

Reference	Feedstock	Product	Energy efficiency or energy consumption	CO_2 emission or carbon efficiency	Cogeneration, etc.
Marano, J.J et al.[2001] (E^{2}S, LLC)	Coal (Illinois)	FT synthetic oil	50.4 %	40.1 %	Shell Design. With conventional product upgrading.
	Coal (Illinois)	FT synthetic oil	52 %	41.1 %	Shell Design. With ZSM-5 product upgrading.
	Coal (Illinois)	FT synthetic oil	47.4 %	37.7 %	Shell Design. With conventional product upgrading + fluidized-bed catalytic cracking for wax conversion.
	Coal (Wyoming)	FT synthetic oil	49.3 %	39.1 %	Shell Design. With conventional product upgrading.

<ii> This Study

[Mining / washing process of imported coal]

As data obtained through hearing surveys with industry related to the coal mining process, Hondo *et al.* [1999] gives figures for fuel input (diesel, gasoline, electricity) per unit weight during coal mining and coal washing for open-pit and underground coal mining in Australia, and calculates environmental burden for the entire lifecycle of imported coal consumption in Japan. These values are also used in CRIEPI [2000] (p.19).
In this study also, energy consumption and GHG emissions were calculated for the extraction process and washing process of imported coal based on data given in Hondo *et al.* [1999], the extraction method at the imported coal source and actual import volumes. Furthermore, regarding energy consumption and CO_2 emission factors during power generation in each country, data reflecting the power generation circumstances of each was created and applied.

[FT synthetic oil production process]

As with methanol production from natural gas, regarding the FT synthetic oil production from coal process, there is no data with a clear basis for calculation. Consequently, in this study, energy consumption and GHG emissions for the FT synthetic oil production from coal process were calculated for two cases, from worst (47.4%) and optimum (52%) fuel efficiency figures given in Marano, J.J *et al.* [2001]. Furthermore, CO_2 emissions calculations were made according to the method used in IAE [1990]. Here, the carbon content in feedstock coal is the weighted average of carbon content (%) in coal from each country and import ratio.

(5) FT Synthetic Oil Production Pathway from Biomass

<i> Existing Study

Table 2.4.7 shows data calculated in prior studies for FT synthetic oil, DME and methanol production from biomass processes.

Table 2.4.7 Energy efficiencies and carbon efficiencies regarding coal based synthetic fuel production pathways in existing studies

Reference	Feedstock	Product	Energy efficiency or energy consumption	CO_2 emission or carbon efficiency	Cogeneration, etc.
Marano, J.J et al.[2001] (E^{2}S, LLC)	Biomass (Maplewood)	FT synthetic oil	51 %	37.2 %	With conventional product upgrading and once-through power generation. BCL Design
Ahlvik, P. et al.[2001] (Ecotraffic)	Biomass	FT synthetic oil	45 %		
Ahlvik, P. et al.[2001] (Ecotraffic)	Biomass	DME	57 %		
Ahlvik, P. et al.[2001] (Ecotraffic)	Biomass	Methanol	54 %	104 g-CO_2/MJ-MeOH	Excluding by-product : hot water.
	Biomass	Methanol	65 %	104 g-CO_2/MJ-MeOH	Including by-product : hot water for district heating.

<ii> This Study

Regarding the FT synthetic oil production from biomass process, energy consumption and GHG emissions were calculated for two cases, from worst (45%) and optimum (51%) fuel efficiency figures given in Ahlvik, P. [2001] and Marano, J.J *et al.* [2001].

(6) DME Production Pathway from Biomass

<i> Existing Study

Shown in Table 2.4.7.

<ii> This Study

Regarding the DME production from biomass process, energy consumption and GHG emissions were calculated from fuels efficiency figures (57%) given in Ahlvik, P. [2001].

(7) Methanol Production Pathway from Biomass

<i> Existing Study

Shown in Table 2.4.7.

<ii> This Study

Regarding the methanol production from biomass process, energy consumption and GHG emissions were calculated for two cases, from worst (54%) and optimum (65%) fuel efficiency figures given in Ahlvik, P. [2001] and Marano, J.J *et al.* [2001].

(8) Overseas Transportation (Sea)

<i> Existing Study

In relation to GTL (FT synthetic oil), NEDO [2001-3] (p. I-124 - I-130) assumes an 80,000 t shipping vessel, and provides fuel consumption data for passage and while moored at loading/unloading ports. In addition, although the report gives the standard vessel size for methanol as 45,000 t, no fuel consumption data is provided. Although there is also no shipping vessel data given for DME, vessels are considered to have the same structural and functional properties as LPG vessels.

PEC [2002-2] gives the vessel size for both GTL and methanol as 50,000 t, with import sources (producing countries) stated as the Southeast Asia, the Middle East and Australia.

<ii> This Study

Regarding FT synthetic oil, this study uses data given for GTL vessels in NEDO [2001-3]. Other than the omission of energy for cargo heating, which is not required for GTL, this data is the same as data for 80,000 t crude oil tankers given in PEC [1998] and PEC [2002-2].

Regarding DME, LPG vessel data used later in "2.5 Liquid Petroleum Gas Production Pathways" also applies here. This data is based on data given in IEEJ [1999] for overseas transportation of LPG, while for vessel speed, figures given in PEC [1998] for crude oil tankers have been substituted.

Regarding methanol, figures given for methanol vessel capacity in NEDO [2001-3] are used, while figures given in the report for GTL vessel speed and fuel consumption have been substituted.

Furthermore, regarding the import sources (producing countries) of each synthetic fuel, for natural gas based fuels, for the five countries (Malaysia, Indonesia, Australia, Iran, Qatar) given in PEC [2002-1] as having a high probability of becoming GTL suppliers to Japan, simple averages were calculated from data per country to obtain final values. For coal based fuels, suppliers were considered based on the actual import volume of coal given in METI [2002], and the weighted average was calculated from the actual import volume as the final value. Australia is considered for biomass based fuels.

(9) Domestic Transportation (Sea/Land)

<i> Existing Study

Regarding the transportation process of synthetic fuels in Japan, NEDO [2001-3] states that GTL and methanol can be handled through the same supply route as gasoline, and DME can be handled through the same route as LPG. In addition, PEC [2002-2] also states that the environmental burden related to the transportation process of GTL and methanol in Japan is the same as for petroleum products.

<ii> This Study

In this study, for FT synthetic oil and methanol, data calculated in "2.1 Petroleum Based Fuel Production

Pathways" for the domestic transportation of diesel has been substituted, while for DME, data related to the domestic transportation of LPG has been substituted.

(10) Energy Efficiency Estimates

In this study, in relation to each synthetic fuel production path, conditions were set for a particular process, and energy efficiency estimates were made according to those conditions.

Regarding the production processes of synthetic fuels from all feedstock types, existing information is insufficient as the number of operational facilities is limited. Therefore, in this study, for reference purposes, energy efficiency estimates were made by calculating material balance and heat balance for the main production processes of each fuel from feedstock, in order to estimate the general energy efficiency of each process. The natural gas considered here is pure CH_4. In addition, as each process involves an exothermic reaction under pressure, calculations were conducted under the assumption that the heat recovered from the main process is used to power the compressor which is the main powered equipment in the process, while energy consumption of processes other than the main process, which was thought to be comparatively small, were not considered in the calculations. The conditions set are shown below.

<i> Syngas production process

Settings for the operating conditions of reformers are shown in Table 2.4.8.

Table 2.4.8 Operating conditions of natural gas reformer

Reforming method	Temperature [℃]	Pressure [MPa]
Steam reforming	850	2.1
Steam/CO_2 reforming	850	2.1
Partial oxidation	1,300	2.1
Autothermal reforming	1,050	2.1
Coal gasification (Shell)	1,371	2.4
Woody biomass	982	3.4

The composition of syngas from natural gas reforming were calculated from equilibrium composition under operating conditions shown in Table 2.4.8 for the reaction combinations given below.

$$CH_4 + H_2O \Leftrightarrow CO + 3H_2 \qquad \text{(formula 1)}$$

$$CO + H_2O \Leftrightarrow CO_2 + H_2 \qquad \text{(formula 2)}$$

$$CH_4 + CO_2 \Leftrightarrow 2CO + 2H_2 \qquad \text{(formula 3)}$$

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O \qquad \text{(formula 4)}$$

Regarding coal gasification and woody biomass, calculations cannot be made as there are no clear reaction formulas such as those above, and data based on actual measurements given in Williams, R.H, *et al.* [1995] and Tijmensen, M.JA. [2000] has been used.

<ii> H_2/CO molar ratios

H_2/CO molar ratios obtained from equilibrium calculations using the above "formula 1" - "formula 4" are shown in Table 2.4.9. "Formula 4" is used for partial oxidation and autothermal reforming.

Table 2.4.9 H_2/CO molar ratio in syngas

Reforming method	H_2/CO molar ratio
Steam reforming	3
Steam/CO_2 reforming	2
Partial oxidation	1.7
Authothermal reforming	2
Coal gasification (Shell)	0.5
Woody biomass	1.4

<iii> Achieve the appropriate H_2/CO molar ratios

When the syngas has a higher H_2/CO molar ratio than required for the subsequent process, the process progresses without any additional action.

On the other hand, when the syngas has a lower H_2/CO molar ratio than required for the subsequent process, a CO shift reaction is introduced to achieve the appropriate H_2/CO molar ratio. As the CO shift reaction is exothermic, values of removed heat were also calculated.

For syngas from biomass, as there is substantial CH_4 residue, the introduction of a CO shift reaction after passage through a reformer was assumed. The heat required by the reformer was assumed to be provided by heat recovered from the subsequent process.

<iv> Calculate the volume of the fuel produced

For the volume of fuel produced in the subsequent process, values were set for CO [kmol] in the syngas, product molecular weight [kg/kmol] and CO conversion rate (CO reaction rate in syngas) [-] (set at 0.95), and calculations were made according to the following formula.

(Synthetic Product Volume [kg])
= (CO [kmol]) * (Product Molecular Weight [kg/kmol]) * (CO conversion rate [-])

For FT synthetics, although various carbon number compounds are generated, FT oil was treated as the total of C5+ constituents (carbon number greater than C5). C_1 - C_4 gas constituents are used as gases (Tijmensen, M.JA. [2000] assumes in-house use for IGCC power generation).

In addition, the constituent ratio of carbon numbers n in FT synthetic oil have been calculated using chain growth probability α through $\alpha(n-1) * (1-\alpha)$, as shown in Figure 2.4.5.

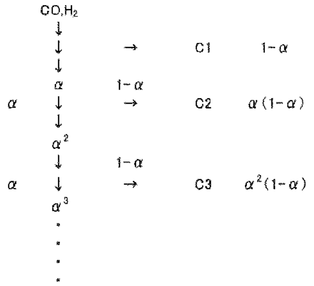

Figure 2.4.5 Composition of FT synthetics

<v> Calculate the product efficiency

Efficiency was then calculated from the product volume obtained through the above using the following formula.

(Product Efficiency [%])
= (Product Volume [kg] * Heating Value [MJ/kg]) / (Feedstock and Fuel Heating Value [MJ]) * 100

2.4.3 Calculation results

Regarding the synthetic fuel production pathways, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.4.10 (energy consumption), Table 2.4.11 (GHG emissions) and Table 2.4.12 (energy efficiency).

Table 2.4.10 WTT energy consumption of synthetic fuel production pathways [MJ/MJ]

	From natural gas				From coal		From biomass				
	FT synthetic oil	DME	Methanol		FT synthetic oil		FT synthetic oil		DME	Methanol	
			best	worst	best	worst	best	worst		best	worst
Upstream process of feedstock	0.017	0.016	0.016	0.017	0.028	0.030	0.074	0.084	0.066	0.058	0.070
Fuel synthesis	0.514	0.404	0.429	0.493	0.923	1.110	0.961	1.222	0.754	0.538	0.852
Overseas transportation	0.017	0.036	0.069	0.069	0.012	0.012	0.013	0.013	0.026	0.050	0.050
Domestic transportation	0.005	0.011	0.010	0.010	0.005	0.005	0.005	0.005	0.011	0.010	0.010
Total	0.553	0.468	0.524	0.589	0.968	1.156	1.052	1.324	0.858	0.657	0.983

* Reference values estimated in this study (tentative calculation) [see (10)]

	From natural gas						From coal			From biomass		
	FT synthetic oil		DME		Methanol		FT synthetic oil	DME	Methanol	FT synthetic oil	DME	Methanol
	best	worst	best	worst	best	worst						
Upstream process of feedstock	0.016	0.023	0.014	0.018	0.019	0.024	0.025	0.028	0.033	0.112	0.062	0.082
Fuel synthesis	0.446	1.025	0.260	0.606	0.678	1.102	0.719	0.695	0.731	1.956	0.649	1.178
Overseas transportation	0.017	0.017	0.036	0.036	0.069	0.069	0.012	0.025	0.047	0.013	0.026	0.050
Domestic transportation	0.005	0.005	0.011	0.011	0.010	0.010	0.005	0.011	0.010	0.005	0.011	0.010
Total	0.484	1.070	0.322	0.671	0.777	1.205	0.761	0.759	0.821	2.085	0.749	1.321

Table 2.4.11 WTT GHG emissions of synthetic fuel production pathways [g eq-CO_2/MJ]

	From natural gas				From coal		From biomass				
	FT synthetic oil	DME	Methanol		FT synthetic oil		FT synthetic oil		DME	Methanol	
			best	worst	best	worst	best	worst		best	worst
Upstream process of feedstock	1.28	1.19	1.21	1.27	10.86	11.87	5.01	5.68	4.48	3.93	4.73
Fuel synthesis	20.00	12.33	15.63	19.42	54.63	54.97	0.00	0.00	0.00	0.00	0.00
Overseas transportation	1.34	2.78	5.28	5.28	0.93	0.93	0.99	0.99	2.03	3.87	3.87
Domestic transportation	0.36	0.84	0.80	0.80	0.36	0.36	0.36	0.36	0.84	0.80	0.80
Total	22.99	17.14	22.93	26.77	66.78	68.14	6.36	7.03	7.35	8.61	9.41
Fixed CO_2							△ 70.76	△ 70.76	△ 66.46	△ 69.00	△ 69.00

* Reference values estimated in this study (tentative calculation) [see (10)]

	From natural gas						From coal			From biomass		
	FT synthetic oil		DME		Methanol		FT synthetic oil	DME	Methanol	FT synthetic oil	DME	Methanol
	best	worst	best	worst	best	worst						
Upstream process of feedstock	1.23	1.72	1.07	1.36	1.42	1.78	9.76	9.87	10.38	7.56	4.22	5.57
Fuel synthesis	14.88	49.20	8.21	28.68	30.44	55.54	48.07	50.69	50.61	0.00	0.00	0.00
Overseas transportation	1.34	1.34	2.78	2.78	5.28	5.28	0.93	1.91	3.65	0.99	2.03	3.87
Domestic transportation	0.36	0.36	0.84	0.84	0.80	0.80	0.36	0.84	0.80	0.36	0.84	0.80
Total	17.82	52.63	12.90	33.66	37.94	63.40	59.13	63.31	65.43	8.91	7.08	10.24
Fixed CO_2										△70.76	△66.46	△69.00

Table 2.4.12 Energy efficiency of synthetic fuel production pathways (LHV)

	From natural gas				From coal		From biomass				
	FT synthetic oil	DME	Methanol		FT synthetic oil		FT synthetic oil		DME	Methanol	
			best	worst	best	worst	best	worst		best	worst
Upstream process of feedstock	0.987	0.987	0.987	0.987	0.993	0.993	↓	↓	↓	↓	↓
Fuel synthesis	0.661	0.712	0.700	0.670	0.520	0.474	0.497	0.439	0.556	0.634	0.527
Overseas transportation	0.983	0.965	0.936	0.936	0.988	0.988	0.987	0.987	0.974	0.952	0.952
Domestic transportation	0.995	0.989	0.990	0.990	0.995	0.995	0.995	0.995	0.989	0.990	0.990
Total	0.638	0.671	0.640	0.613	0.508	0.463	0.489	0.431	0.536	0.597	0.496

* Reference values estimated in this study (tentative calculation) [see (10)]

	From natural gas						From coal			From biomass		
	FT synthetic oil		DME		Methanol		FT synthetic oil	DME	Methanol	FT synthetic oil	DME	Methanol
	best	worst	best	worst	best	worst						
Upstream process of feedstock	0.987	0.987	0.987	0.987	0.987	0.987	0.993	0.993	0.992	↓	↓	↓
Fuel synthesis	0.692	0.494	0.793	0.623	0.596	0.476	0.582	0.590	0.578	0.330	0.591	0.448
Overseas transportation	0.983	0.983	0.965	0.965	0.936	0.936	0.988	0.976	0.955	0.987	0.974	0.952
Domestic transportation	0.995	0.995	0.989	0.989	0.990	0.990	0.995	0.989	0.990	0.995	0.989	0.990
Total	0.668	0.477	0.748	0.587	0.545	0.435	0.568	0.565	0.542	0.324	0.570	0.422

2.5 Liquefied Petroleum Gas Production Pathways

2.5.1 Abstract

LPG is a hydrocarbon with carbon number 3 or 4, specifically propane, propylene, butane, butylene, or other petroleum products with these as the main constituents (see 2.1.1 (5)).
LPG production methods include the following three methods.

1) Gas associated with crude oil from oil fields is separated and refined and LPG is collected
   (associated gas derivative)
2) Gas extracted from gas fields (mainly CH_4) is separated and refined, and LPG is collected
   (raw natural gas derivative)
3) Collection as a byproduct gas at petroleum refineries/petrochemical plants
   (from petroleum refining)

Of these, the process of 2) up to the processing/liquefaction process is calculated in "2.2 Natural Gas Based Fuel Production Pathways", and the process of 3) up to the petroleum refining process is calculated in "2.1 Petroleum Based Fuel Production Pathways". Here, along with calculations for the LPG production from associated gas pathways of 1), weighted average values for actual LPG supply and demand ratio in Japan (associated gas derivative 61.4%, raw natural gas derivative 15.4%, petroleum refining derivative 23.2% (Source: IEEJ [1999] (p.37))) were also calculated for each pathway.

2.5.2 Procedures for data collection of unit process

LPG production pathway flow examined in this study are shown in Figure 2.5.1:

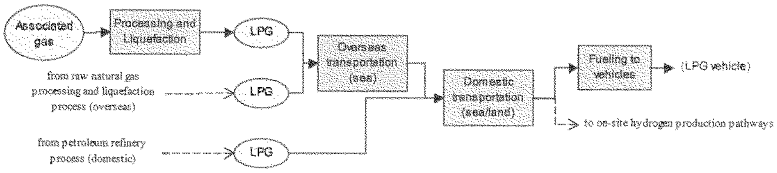
Associated gas
Processing and Liquefaction
LPG
from raw natural gas processing and liquefaction process (overseas)
LPG
from petroleum refinery process (domestic)
LPG
Overseas transportation (sea)
Domestic transportation (sea/land)
Fueling to vehicles
(LPG vehicle)
to on-site hydrogen production pathways

Figure 2.5.1 Pathway flow for LPG production

(1) Processing and Liquefaction of Associated Gas

<i> Existing Study

The CO_2 emissions values given on a calorific basis for the production (extraction) process, accompanying flare combustion and CH_4 vent, in IEEJ [1999] (p.35), are the same values calculated for petroleum products inventory data in the report. In addition, as data could not be obtained for the processing/liquefaction process, a simulation was conducted based on the specifications of an overseas processing/liquefaction plant of the same scale. Furthermore, the report contains no mention of associated CO_2, even in the petroleum products section, and seems to assume that CO_2 will not be generated even in the processing/liquefaction process of LPG from associated gas.

<ii> This Study

For the production (extraction) process, this study uses the calculation results of "2.1 Petroleum Based Fuel Production Pathways". In addition, regarding the processing/liquefaction process, CO_2 emissions are quoted from simulation values in IEEJ [1999] (p.50), and energy consumption was calculated according to the data upon which the same simulation was based.

(2) Overseas Transportation (Sea)

<i> Existing Study

IEEJ [1999] (p.35) considers the tank capacity and stowage factor of a standard LPG shipping vessel, assumes the fuel used to be C-heavy fuel oil and A-heavy fuel oil and, taking the propane and butane ratio of LPG for each region into account, cites weighted averages for CO_2 emissions based on import distribution ratios for 1997.

<ii> This Study

This study cites values given in IEEJ [1999] (p.51) for data related to LPG vessels, and calculates import distribution ratio using actual figures for 2001. Regarding LPG vessel speed, which is not mentioned in IEEJ [1999], the value given in PEC [1998] for 80,000 t and 100,000 t crude oil tankers (15.1 knots) was used. Furthermore, although IEEJ [1999] considers LPG vessel tank capacity in m^3 units, as LPG is shipped in liquid form over the marine shipping process, unit notation here has been changed to kL to avoid confusion.

(3) Domestic Transportation (Sea/Land)

<i> Existing Study

Although IEEJ [1999] gives figures for CO_2 emissions for domestic LPG transportation under the assumption of overland transportation (tank lorry) and coastal transportation (coastal tanker), the reasoning behind the calculations is not clear.

<ii> This Study

In this study, values for the domestic transportation process of petroleum based fuel production pathways (gasoline) have been substituted.

(4) Fueling to Vehicles

As the main constituent of LPG for vehicles is butane, as with gasoline the energy consumption for supply to vehicles is considered negligible. Consequently, this study treats this value as zero.

2.5.3 Calculation results

Regarding the LPG production pathways, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.5.1 (energy consumption), Table 2.5.2 (GHG emissions) and Table 2.5.3 (energy efficiency).

Table 2.5.1 WTT energy consumption of LPG production pathways [MJ/MJ]

		From associated gas	From raw natural gas	From petroleum refinery	Weighted average
Shares		61.4%	15.4%	23.2%	100%
Extraction	Operation	0.012	0.011	0.011	0.012
	Flare combustion	0.006	0.002	0.006	0.005
Processing / liquefaction	Operation	0.059	0.099	-	0.052
	Flare combustion	-	0.009	-	0.001
Overseas transportation		0.035	0.035	0.011	0.030
Petroleum refining		-	-	0.116	0.027
Domestic transportation		0.007	0.007	0.007	0.007
Fueling to vehicles		0.000	0.000	0.000	0.000
Total		0.120	0.163	0.151	0.134

Table 2.5.2 WTT GHG emissions of LPG production pathways [g eq-CO_2/MJ]

		From associated gas	From raw natural gas	From petroleum refinery	Weighted average
Shares		61.4%	15.4%	23.2%	100%
Extraction	Operation	0.75	0.49	0.70	0.70
	Flare combustion	0.37	0.15	0.35	0.34
	CH_4 vent	0.04	0.22	0.03	0.06
Processing / liquefaction	Operation	3.36	5.34	-	2.88
	Flare combustion	-	0.42	-	0.06
	CH_4 vent	-	0.56	-	0.09
Associated CO_2		0.00	1.90	0.30	0.36
Overseas transportation		2.72	2.72	0.85	2.28
Petroleum refining		-	-	7.16	1.66
Domestic transportation		0.52	0.52	0.52	0.52
Fueling to vehicles		0.00	0.00	0.00	0.00
Total		7.76	12.32	9.93	8.96

Table 2.5.3 WTT energy consumption of LPG production pathways (LHV)

	From associated gas	From raw natural gas	From petroleum refinery	Weighted average
Shares	61.4%	15.4%	23.2%	100%
Extraction	0.982	0.987	0.982	-
Processing / liquefaction	0.944	0.901	-	-
Overseas transportation	0.966	0.966	0.988	-
Petroleum refining	-	-	0.950	-
Domestic transportation	0.993	0.993	0.993	-
Fueling to vehicles	1.000	1.000	1.000	-
Total	0.889	0.853	0.916	0.890

2.6 Electricity (Electric Power Generation Pathways)

2.6.1 Abstract

Power generation can be broadly classified into hydroelectric power generation, thermal power generation, nuclear power generation, and other power generation methods using natural energy such as solar power, wind power, geothermal power and biomass power generation which uses waste wood. From the perspective of automotive fuel production, electricity can be used in electric vehicles and in electrolysis for hydrogen production.

(1) Hydroelectric Generation

This method of generation utilizes the power of falling water (potential energy) to turn generators and produce electricity. As this system can be activated and deactivated at short notice, it can be used to supply power at peak power consumption times during the day and to respond to sharp variations in demand. For a nation like Japan, relying mainly on imports for energy, hydroelectric power generation, which utilizes the abundant water resources, is a valuable purely domestic energy source in which much hope is placed.

(2) Thermal Power Generation

This method burns fossil fuels such as petroleum, LNG and coal in boilers to produce high-temperature/ high-pressure steam, which is then used to turn turbines and generate electricity. This system provides high output power generation and also allows output to be adjusted to demand, performing a central role in present day power generation. There are four types of thermal power generation:

<i> Steam power

Fuel is burned in boilers to produce high-temperature/high-pressure steam, which is used to turn turbines and generate electricity. At present, thermal power generation accounts for an overwhelmingly large proportion of power generation capacity and output.

<ii> Internal combustion power

Internal combustion engines such as diesel engines are used to generate electricity. This is used in small-scale power generation mainly on isolated islands.

<iii> Gas turbine power

Combustion gas from fuels such as kerosene and diesel are used to turn turbines and generate electricity. This method is used in response to demand at peak times.

<iv> Combined cycle thermal power

This is a new power generation method with excellent heat efficiency, which combines gas turbines and steam turbines. This system can easily be activated and deactivated at short notice, and allows instantaneous response to sharp variations in demand.

(3) Nuclear Power Generation

With nuclear power generation, the heat generated by the nuclear fission of uranium within a nuclear reactor is used to produce high-temperature/high-pressure steam, which is used to turn turbines and generate electricity. Although there are a number of nuclear reactor types, reactors most commonly in use in Japan are light water reactors.

Light water reactors are the reactor type most commonly in use throughout the world, using moderators (substance which retards the speed of neutrons generated through fission to facilitate subsequent fission), coolants (fluid used to remove heat generated by fission from reactor core) and light water (normal water).

There are two types of light water reactor, (1) the Boiling Water Reactor (BWR) and (2) the Pressurized Water Reactor (PWR), with both reactor types in equal use in Japan. BWR is a method in which steam generated inside the reactor is sent directly to the turbine. After turning the turbine, the steam is cooled in a condenser, reduced to water, and then returned to the reactor. On the other hand, the PWR method sends hot water generated in the reactor to a steam generator, where this water converts water running in a separate system to steam, which is then used to turn turbines.

(4) Solar Power Generation

This is a power generation method that utilizes solar batteries (photoelectric cells), which produce electricity when exposed to light. While this energy source is "clean" and inexhaustible, it requires vast surface area to generate large amounts of power, is subject to the weather, and cannot be utilized at night. Japan leads the world in the implementation of solar power generation, and although there are still many problems to solve, the use of solar power as a distributed power source is increasing.

(5) Wind Power Generation

This method generates electricity by utilizing wind to turn windmills, which turn generators. Since the Oil Crisis of 1973, wind power generation gained prominence throughout the world, especially in the U.S. and Canada, as the new energy to replace oil. The low energy density of wind, the high-energy fluctuation, and issues concerning durability and reliability due to the severe climate in locations in Japan applicable for wind power generation, remain to be solved.

(6) Geothermal Power Generation

Geothermal power generation is a method that generates electricity by turning turbines using steam generated underground. According to no fuel costs, the high operating rate and a cheap and safe energy source, it has already been industrialized. Problems with this method include difficulties in constructing high capacity power plants, plant sites limited to volcanic zones, and the high cost and time involved in investigating suitable sites.

(7) Biomass Power Generation

Through thermochemical conversion such as direct combustion and gasification, or biochemical conversion such as CH_4 fermentation, biomass energy is converted into steam or gas and used to generate electricity. The former mainly uses dry biomass such as wood and rice straw, while the latter uses wet biomass such as livestock waste, raw garbage and sewage sludge. For the power generation method, steam turbines, gas turbines and gas engines are used.

For direct combustion-steam turbine power generation, biomass is burned directly in a boiler and the resulting steam is used to turn a turbine and generate electricity. This method is currently the most common. Stoker and fluid bed furnaces are commonly used direct combustion furnaces. Problems with biomass power generation using steam turbines include low generating efficiency.

Gasification-gas turbine power generation exhibits higher generating efficiency in comparison to steam turbine power generation, and with the advantage of requiring smaller initial investment, this method is drawing attention as the biomass power generation method of the near future. In addition, since gas turbine power generation exhibits high efficiency even on a small scale, it is an effective system for distributed power generation, such as biomass power generation.

CH_4 fermentation-gas engine power generation generates power through gas engines which use gas obtained from the CH_4 fermentation of animal manure, raw garbage, sewage sludge, and so on (generally CH_4: 60-70%, CO_2: 30-40%). Rather than energy use, the main objectives are related to control of waste processing problems such as bad smells and landfill site acquisition, and the inhibition of CH_4, a greenhouse gas, and in general the scale of individual plants is small. When considering energy use as the main objective, problems such as lengthy fermentation time are apparent.

Furthermore, for considerations of energy efficiency during power generation in this study, the effects of power conversion are treated as virtually non-existent in relation to hydroelectric, solar, wind and geothermal power generation, and efficiency is considered only in terms of the power generated. Consequently, calculations conducted here are for energy consumption, GHG emissions and energy efficiency over the lifecycle, from extraction of feedstock to power generation, in relation to all types of thermal, nuclear and biomass power generation.

Descriptions of the above power generation methods are from The Federation of Electric Power Companies of Japan website (http://www.fepc.or.jp/hatsuden/index.html) and Saka [2001].

2.6.2 Procedures for data collection of unit process

Power generation pathway flow examined in this study are shown in Figure 2.6.1:

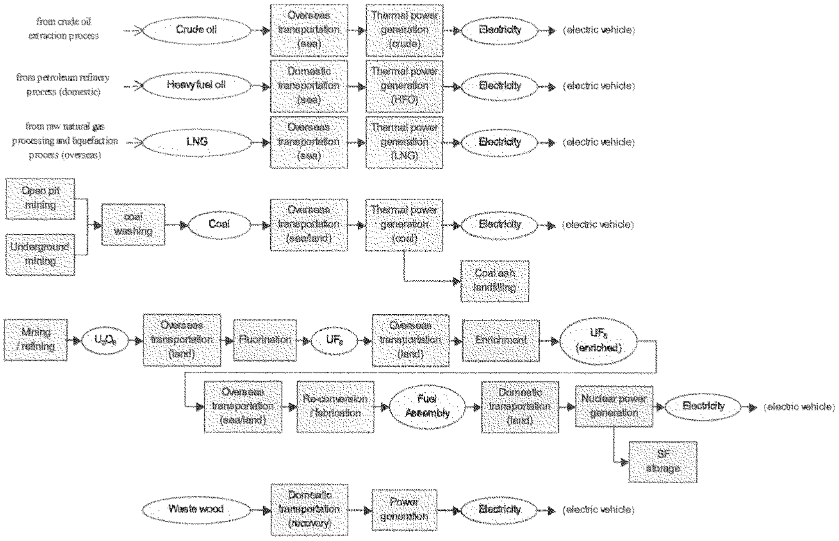
from crude oil extraction process
Crude oil
Overseas transportation (sea)
Thermal power generation (crude)
Electricity
(electric vehicle)
from petroleum refinery process (domestic)
Heavy fuel oil
Domestic transportation (sea)
Thermal power generation (HFO)
from raw natural gas processing and liquefaction process (overseas)
LNG
Overseas transportation (sea)
Thermal power generation (LNG)
Open pit mining
Underground mining
coal washing
Coal
Overseas transportation (sea/land)
Thermal power generation (coal)
Coal ash landfilling
Mining /refining
U_3O_8
Overseas transportation (land)
Fluorination
UF_6
Overseas transportation (land)
Enrichment
UF_6 (enriched)
Overseas transportation (sea/land)
Re-conversion /fabrication
Fuel Assembly
Domestic transportation (land)
Nuclear power generation
SF storage
Waste wood
Domestic transportation (recovery)
Power generation

Figure 2.6.1 Pathway flow for power generation

(1) Petroleum Fired Thermal Power Generation

<i> Existing Study

IAE [1990] (p.144) calculates CO_2 emissions for the power generation stages based on the FY1988 annual average values for generating efficiency (38.84%), power distribution efficiency (37.18%) and in-house ratio (4.27%).

CRIEPI [1991] (p. 19-27) calculates the energy input and energy balance of petroleum fired thermal power generation, assuming values for petroleum fired plant capacity (generating end output) at 1,000 MW, capability factor 75 %, generating efficiency (generating end) 39 % and in-house ratio 6.1 %. Although the later studies implemented by CRIEPI (CRIEPI [1992], [1995]) have some adjustments, they are based on data given in CRIEPI [1991]. In addition, CRIEPI [2000] re-estimates GHG emissions over the lifecycle of petroleum fired power generation technology using technology and import conditions of power generation fuels for 1996 as a point of reference. All studies conducted by CRIEPI consider not only the fuel lifecycle, but also construction of power plant and so on.

<ii> This Study

[Overseas transportation (sea)]

Regarding overseas transportation (sea) of crude for power generation, calculation results given in "2.1 Petroleum Based Fuel Production Pathways" are used.

[Domestic transportation]

Regarding the domestic transportation of heavy fuel oils, calculation results given in "2.1 Petroleum Based Fuel Production Pathways" are used.

[Petroleum fired thermal power generation]

Petroleum fired thermal power plant energy consumption and GHG emissions (based on sending end) were calculated based on year 2000 actual values for fuel consumption, generating end heat efficiency, in-house ratio, power generation (sending end, receiving end), distribution loss ratio and distribution loss, given in ANRE [2002-3] for petroleum fired thermal power plants.

Other than the above, with regards to the operating process of petroleum fired power plants, CRIEPI [2000] (p.26) also calculates consumption of limestone and ammonia required for desulfurization and denitration. This study also follows this example. Inventory data for limestone and ammonia production is cited from NEDO [1995] (p.130). This inventory data was researched and created by National Institute for Resources and Environment (current National Institute of Advanced Industrial Science and Technology), a subordinate body of the Agency of Industrial Science and Technology.

(2) LNG Fired and LNG Combined Cycle Thermal Power Generation

<i> Existing Study

IAE [1990] (p.145-146) calculates CO_2 emissions for the power generation stages based on the FY1988 annual average values for generating efficiency (LNG: 39.29 %, LNG combined cycle 42.42 %), power distribution efficiency (LNG: 37.82 %, LNG combined cycle: 41.38 %) and in-house ratio (LNG: 3.75 %, LNG combined cycle: 2.45 %).

CRIEPI [1991] (p.27-31) calculates the energy input and energy balance of LNG fired thermal power generation, assuming values for LNG fired plant capacity (generating end output) at 1,000 MW, capability factor 75 %, generating efficiency (generating end) 39 % and in-house ratio 3.5 %. Although the later studies implemented by CRIEPI (CRIEPI [1992], [1995]) have some adjustments, they are based on data given in CRIEPI [1991]. In addition, CRIEPI [2000] re-estimates GHG emissions over the lifecycle of LNG fired power generation technology using technology and import conditions of power generation fuels for FY1996 as a point of reference. All studies conducted by CRIEPI consider not only the fuel lifecycle, but also construction of power plant and so on.

<ii> This Study

[Overseas transportation (sea)]

Regarding overseas transportation (sea) of LNG for power generation, calculation results given in "2.2 Natural Gas Based Fuel Production Pathways" are used.

[LNG fired and LNG combined cycle thermal power generation]

LNG fired and LNG combined cycle thermal power plant energy consumption and GHG emissions (based on sending end) were calculated based on FY2000 actual values for fuel consumption, generating end heat efficiency, in-house ratio, power generation (sending end, receiving end), distribution loss ratio and distribution loss, given in ANRE [2002-3] for LNG fired and LNG combined cycle thermal power plants.

In addition, as with petroleum fired thermal power generation, regarding the operating process of LNG fired and LNG combined cycle thermal power plants, CRIEPI [2000] (p.26) calculates consumption of limestone and ammonia required for desulfurization and denitration. This study also follows this example.

(3) Coal Fired Thermal Power Generation

<i> Existing Study

IAE [1990] (p.147) calculates CO_2 emissions for the power generation stages based on the FY1988 annual average values for generating efficiency (39.37 %), power distribution efficiency (36.26 %) and in-house ratio (7.96 %).

CRIEPI [1991] (p.11-19) calculates the energy input and energy balance of coal fired thermal power generation, assuming values for coal fired plant capacity (generating end output) at 1,000 MW, capability factor 75 %, generating efficiency (generating end) 39 % and in-house ratio 7.4 %. Although the later studies implemented by CRIEPI (CRIEPI [1992], [1995]) have some adjustments, they are based on data given in CRIEPI [1991]. In addition, CRIEPI [2000] re-estimates GHG emissions over the lifecycle of coal fired power generation technology using technology and import conditions of power generation fuels for 1996 as a point of reference. All studies conducted by CRIEPI consider not only the fuel lifecycle, but also construction of power plant and so on.

<ii> This Study

[Coal mining / washing]

As data obtained through hearing surveys with industry related to the coal mining process, Hondo *et al.* [1999] gives figures for fuel input (diesel, gasoline, electricity) per unit weight during coal mining and coal washing for open-pit and underground coal mining in Australia, and calculates environmental burden for the entire lifecycle of imported coal for power generation consumed in Japan. These values are also used in CRIEPI [2000] (p.19).

In this study also, energy consumption and GHG emissions were calculated for the extraction process and washing process of imported coal based on data given in Hondo *et al.* [1999], the extraction method at the imported coal source and actual import volumes. Furthermore, regarding energy consumption and CO_2 emission factors during power generation in each country, data reflecting the power generation circumstances of each was created and applied.

Regarding CH_4 vent, values per country were taken from IEEJ [1999] (p.13) and the weighted average was calculated using import volumes given in ANRE [2002-1].

[Overseas transportation (land / sea)]

Regarding overland transportation of coal at the producing region, both IEEJ [1999] (p.6) and CRIEPI [2000] (p.17) conduct calculations on the assumption that all transportation of coal for export from the producing region to the shipping port takes place via rail. In addition, although there are various electrification conditions concerning the railways of each country, the use of diesel engines is assumed, and consequently the fuel consumed is diesel. Regarding fuel consumption factor, values given in Ministry of Transport (MOT) Transport Policy Bureau [2000] are used.

This study also adopted the same calculation methods used in prior studies. The overland transportation distances in the producing country were taken from values (one-way) given in IEEJ [1999] (p.12). Energy consumption and GHG emissions for the overland transportation of coal in the producing country were calculated using the weighted average of these values multiplied by fuel consumption factor (0.0126 L/t-km), and import volumes given in ANRE [2002-1].

Regarding the overseas transportation (sea) of coal, energy consumption and GHG emissions for the overseas transportation of coal was calculated using values taken from NEDO [1996] (p.105-106) for average vessel size for transportation (50,000 t deadweight tonnage), speed (15 knots) and fuel consumption (60 kg-C-heavy fuel oil/km), and import volume and distance from port of shipment to Japan. In addition, regarding loading and unloading (energy consumption through handling), values given in IAE [1990] (p.138) were used. Although the values given here are for electricity consumption (0.95 kWh/t) per t coal at Tomakomai Port, Hokkaido, since there is generally little difference in energy consumption through handling for either loading or unloading (IAE [1990]), this study substitutes values for energy consumption per t coal at Tomakomai Port for energy consumption at the port of shipment for each country.

[Coal fired thermal power generation]

Coal fired thermal power plant energy consumption and GHG emissions (based on sending end) were calculated based on year 2000 actual values for fuel consumption, generating end heat efficiency, in-house ratio, power generation (sending end, receiving end), distribution loss ratio and distribution loss, given in ANRE [2002-3] for coal fired thermal power plants.

As with other forms of thermal power generation, regarding the operating process of coal fired thermal power plants, CRIEPI [2000] (p.26) calculates consumption of limestone and ammonia required for desulfurization and denitration. This study also follows this example.

[Coal ash landfilling]

CRIEPI [2000] (p.27) calculates energy consumption required for coal ash landfilling from data obtained through hearing surveys with related industry. This study also follows this example.

(4) Nuclear Power Generation

<i> Existing Study

CRIEPI [1991] (p.31-36) conducts calculations for PWR light water reactors assuming plant capacity at 1,000 MW, capability factor 75 %, and in-house ratio 3.4 %. Furthermore, regarding data from each process, from uranium extraction to enrichment, shaping and transportation, as no publicly disclosed data was available in Japan, U.S. data (Asad T. Amr [1981]) has been used for reference.

CRIEPI [2000] (p. 27-32) conducts calculations for the nuclear fuel production process using Institute for Policy Sciences (IPS) [1977], and calculations for the power generation process (plant operation), energy consumption per unit power generation, based on average values of eight power plants obtained through hearing surveys conducted with electricity companies. However, as some data could not be obtained in relation to uranium enrichment for nuclear power generation, analysis has been conducted under the assumption that all enrichment will be conducted in the U.S. using the gas diffusion method. In addition, power generation systems, which reprocess spent fuel and use the resultant MOX fuel, have not been considered.

Consequently, CRIEPI [2001], released the following year, uses data that more accurately reflects actual status concerning uranium enrichment, and provides analyses of CO_2 emissions over the nuclear power generation lifecycle that reflects actual status in Japan. Furthermore, analysis is also provided concerning the possible effects the nuclear fuel cycle currently being planned in Japan may have on CO_2 emissions over the entire lifecycle.

Furthermore, all the above CRIEPI studies consider not only the fuel lifecycle, but also construction of power plant and so on.

<ii> This Study

In principle, this study used CRIEPI [2001] for reference. However, in order to be consistent with other fuel production pathways, power plant construction and so on, was excluded from evaluation. In addition, only the basic BWR and PWR systems were considered, and recycling systems that use MOX fuel produced from reprocessed spent nuclear fuel are also excluded from evaluation.

[Mining / Refining]

Annual energy consumption and data per kWh were calculated based on data for nuclear fuel requirements and energy consumption for the production of 1 t-U yellow cake. Uranium ore mining is assumed to be at 5,000 t-ore per day through open-pit mining. In relation to refining, considerations are for facilities with an annual yellow cake production capacity of 1,350 t-U and a serviceable life of thirty years. The data is from IPS [1977].

[Conversion (Fluorination)]

Annual energy consumption and data per kWh were calculated based on data for resource requirements and energy consumption for the production of 1 t-U UF_6. Considerations are for facilities with an annual UF_6 production capacity of 5,000 t-U and a serviceable life of thirty years. The data is from IPS [1977].

[Enrichment]

Enrichment methods taken into consideration are the gas diffusion method (overseas) and the centrifugal separation method (domestic and overseas).

Gas diffusion facilities (overseas) with a production capacity of 8,750 t-SWU[4]/year and serviceable life of 30 years, centrifugal separation facilities (domestic) with a production capacity of 600 t-SWU/year and serviceable life of 40 years, and centrifugal separation facilities (overseas) with a production capacity of 1,000 t-SWU/year and serviceable life of 30 years, are considered. According to CRIEPI [2001], basic data for gas diffusion (overseas) and centrifugal separation (overseas) is from IPS [1977], while basic data for centrifugal separation (domestic) is taken from internal papers of the Tokyo Electric Power Company (TEPCO) Energy/Environment Technology Research Institute.

Annual consumption and data per kWh were calculated based on data for resource requirements and energy consumption to produce 1 t-U of enriched UF_6.

[Re-conversion / Fabrication]

Annual consumption and data per kWh were calculated based on data for resource requirements and energy consumption to produce 1 t-U of fuel assembly. Considerations are for facilities with an annual production capacity of 900 t-U and a serviceable life of 30 years. The data is generally cited from IPS [1977].

[Domestic transportation (sea)]

Although CRIEPI [2000] calculates data for each transportation process, this study cites aggregate data given in CRIEPI [2001].

[Power generation]

Nuclear fuel requirements for 1 year were estimated using the following formula (CRIEPI [2000] (p.28)).

[Nuclear Fuel Consumption]
= [Generating Capacity] * 365 * [Capability factor] / ([Combustion degree] * [Heat Efficiency])

Energy consumption and GHG emissions were calculated from fuel consumption for supplementary boilers used for power plant heating and so on. These are average values of eight power plants obtained through hearing surveys conducted with electricity companies.

[Storage of spent fuel assembly]

Data per kWh was calculated based on energy consumption data for the storage of one BWR spent fuel assembly for one year. Here, data given in CRIEPI [2001] for naturally ventilated facilities with dry cask storage capacity of 860 assemblies of 8 * 8 fuel is cited as given, with calculations conducted for a 50-year-storage term. Data for the interim storage of spent fuel was sourced from TEPCO Energy/Environment Technology Research Institute internal papers.

On the other hand, regarding PWR, CRIEPI [2001] cites BWR data, as data for the long-term interim storage of spent PWR fuel was not available. Consequently, this study has also adopted this method.

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[4] Separative Work Unit

(5) Biomass Power Generation (Direct combustion-steam turbine power generation)

<i> Existing Study

Although biomass comes in a variety of forms such as raw garbage and woody biomass, power generation through incineration has long since been implemented for municipal waste containing raw garbage. Hokkaido University Graduate School of Engineering [1998] conducts a life cycle analysis of municipal waste incineration power plants. Regarding woody biomass studied in this study, Ohki *et al.* [2002] provides data concerning woodchip fired boiler power generation currently implemented or planned in Japan.

<ii> This Study

Calculations in this study are based on Ohki *et al.* [2002]. As biomass power plants normally operate using part of the power generated from biomass for in-house power, all plant operating energy is derived from biomass, and therefore CO_2 emissions derived from fossil fuels can be treated as zero. However, as the plant consumes chemicals for exhaust gas treatment, calculations include energy required for the production of these chemicals.

(6) Biomass Power Generation (Gasification-gas turbine power generation)

<i> Existing Study

The power generation system considered here is the IGCC system (combination of gas turbine power generation and boiler power generation from exhaust heat), which generates electricity using syngas obtained through the gasification of biomass. Regarding municipal waste including raw garbage, although many domestic furnace makers have developed gasification melting power generation systems, since the majority of these involve normal boiler power generation without gas turbines, they are not included in the gasification power generation of prior studies mentioned here. Mann, M.K., *et al.* [1997] uses a simulation to provide a life cycle analysis of woody biomass (hybrid poplar) gasification power generation. Details of actual gasification power plants are given in Krister Ståhl, *et al.* [2000]. This report provides general data (e.g. generating efficiency) for a gasification power plant using woody biomass currently in operation in Varnamo, Sweden.

<ii> This Study

Calculations in this study are based on Mann, M.K., *et al.* [1997] (p.21), which contains all the necessary data. Although the majority of energy consumed can be attributed to power for operation, as all this power is generated in-house through biomass, CO_2 emissions derived from fossil fuels can be treated as zero. In addition, as exhaust gas treatment only involves dust in the exhaust gas, the use of chemicals is not considered. Krister Ståhl, *et al.* [2000] gives a figure of 32 % for generating efficiency (net), which is generally in the same range as Mann, M.K. *et al.* [1997].

(7) Biomass Power Generation (CH_4 fermentation-gas engine power generation)

<i> Existing Study

Operational data for actual gas engine power plants using digestion gas obtained through CH_4 fermentation (gas containing CH_4 gas) are given in Ogawa *et al.* [2003]. The plant generates 3,200 kWh/day through the CH_4 fermentation of livestock manure, bean curd lees and sewage sludge from in-house wastewater processing facilities.

Facilities which compost dehydrated cake remaining after CH_4 fermentation are also included.

<ii> This Study

Calculations in this study are based on Ogawa *et al.* [2003], which provides detailed data on actual operations. Power consumed by facilities which compost dehydrated cake remaining after CH_4 fermentation is calculated as beyond the sphere of the system. As previously mentioned, the main raw biomass is livestock manure and bean curd lees, which differs from dry biomass such as wood, in that the water content is extremely high. Consequently, the in-house wastewater treatment load is high, and although the gas engine generating efficiency is comparatively high at 29 %, the overall generating efficiency of the plant (net) is low.

(8) Distribution Loss

Distribution loss occurring during distribution from large-scale intensive power plants, such as all thermal and nuclear power plants, to consumers, is calculated based on values for power generation at sending end and receiving end, given in ANRE [2002-1].

Furthermore, the same value for distribution loss has been applied to petroleum fired, LNG fired and LNG combined cycle, coal fired and nuclear power generation.

2.6.3 Calculation results

Regarding electricity (power generation pathway), calculation results for energy consumption, GHG emissions and energy efficiency during 1MJ power generation are shown in Table 2.6.1 (energy consumption), Table 2.6.2 (GHG emissions) and Table 2.6.3 (energy efficiency).

Table 2.6.1 WTT energy consumption of power generation pathways [MJ/MJ]

	Thermal				Nuclear		Biomass			Japan average (2000FY)
	Petroleum	LNG	LNG combined	Coal	BWR	PWR	Direct combustion	Gasification	CH_4 fermentation	
Total upstream process	0.181	0.386	0.333	0.115	0.119	0.155	0.506	0.089	0.553	0.259
(Crude oil)	(0.031)	(0.002)	(0.000)							(0.002)
(Heavy fuel oil)	(0.146)	(0.006)		(0.002)						(0.014)
(LNG)		(0.374)	(0.333)							(0.099)
(Coal)				(0.112)						(0.016)
(Nuclear fuel)					(0.119)	(0.155)				(0.127)
(others)	(0.004)	(0.004)	(0.001)	(0.001)			(0.506)	(0.089)	(0.553)	(0.001)
Fuel combustion (power generation)	1.770	1.527	1.081	1.662	0.002	0.002	5.150	0.761	0.479	1.614
Ash landfilling, SF storage, etc.					0.004	0.004				0.004
Distribution loss										
Total	1.951	1.913	1.414	1.777	0.125	0.160	5.656	0.850	1.032	1.877

Table 2.6.2 WTT GHG emissions of power generation pathways [g eq-CO_2/MJ]

	Thermal				Nuclear		Biomass			Japan average (2000FY)
	Petroleum	LNG	LNG combined	Coal	BWR	PWR	Direct combustion	Gasification	CH_4 fermentation	
Total upstream process	12.54	30.25	26.21	21.70	5.72	7.41	45.34	7.97	41.17	18.71
(Crude oil)	(2.31)	(0.14)	(0.01)							(0.18)
(Heavy fuel oil)	(9.96)	(0.43)		(0.15)						(0.93)
(LNG)		(29.44)	(26.17)							(7.77)
(Coal)				(21.51)						(3.70)
(Nuclear fuel)					(5.72)	(7.41)				(6.06)
(others)	(0.26)	(0.25)	(0.04)	(0.04)			(45.34)	(7.97)	(41.17)	(0.08)
Fuel combustion (power generation)	205.13	145.26	117.54	250.89	0.12	0.12				104.20
Ash landfilling, SF storage, etc.				0.01	0.16	0.16				0.15
Distribution loss										
Total	217.66	175.51	143.75	272.60	6.00	7.70	45.34	7.97	41.17	123.06

Table 2.6.3 WTT energy efficiency of power generation pathways (LHV)

	Thermal				Nuclear		Biomass			Japan average (2000FY)
	Petroleum	LNG	LNG combined	Coal	BWR	PWR	Direct combustion	Gasification	CH_4 fermentation	
Total upstream process	0.928	0.858	0.858	0.964	↓	↓	0.674	0.921	0.653	0.948
(Crude oil)	(0.972)									(0.972)
(Heavy fuel oil)	(0.891)									(0.891)
(LNG)		(0.858)	(0.858)							(0.858)
(Coal)				(0.964)						(0.964)
(Nuclear fuel)					↓	↓				–
(others)							(0.674)	(0.921)	(0.653)	–
Fuel combustion (power generation)	0.402	0.431	0.513	0.417	0.966	0.957	0.145	0.372	0.292	0.383
Ash landfilling, SF storage, etc.				1.000	↑	↑				1.000
Distribution loss	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959
Total	0.358	0.354	0.422	0.386	0.927	0.918	0.094	0.329	0.183	0.348

2.7 Hydrogen Production Pathways

2.7.1 Abstract

Hydrogen is a nonmetallic element, atomic number 1, represented by the atomic symbol "H". It is the lightest and most common element in the universe and exists profusely in water, organic compounds and life forms. Hydrogen is colorless, odorless and highly combustible. Lately, from the global environment perspective, hydrogen energy, which produces only water on combustion, is drawing attention.

Various supply and production methods have been proposed concerning the supply of hydrogen as an automotive fuel for FCVs.

(1) Hydrogen Production by Stream Reforming

Steam reforming is a method in which steam is added to a hydrocarbon feedstock to promote a reforming reaction and produce a syngas containing hydrogen.

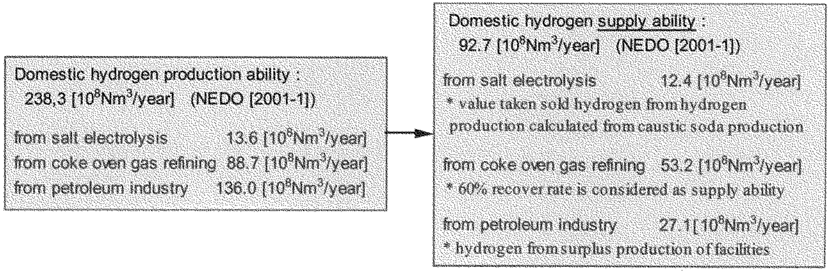
Promising feedstock for steam reforming include methanol, city gas (natural gas), LNG, LPG, desulfurized gasoline and so on, and a field test of a refueling station for hydrogen from reformed natural gas has been conducted (NEDO [2001-2]).

(2) Byproduct Hydrogen

Byproduct hydrogen refers to hydrogen that is obtained as a byproduct of another process. Byproduct hydrogen can be broadly classified into three categories:

- Hydrogen from salt electrolysis: Hydrogen that is produced during the electrolysis of industrial salt to produce caustic soda. Hydrogen refueling stations providing salt electrolysis hydrogen are already in operation
- Hydrogen from coke oven gas refining: Hydrogen contained in coke oven gas produced during the carbonization of coal to produce coke for the iron and steel industry
- Hydrogen from petroleum industry: Hydrogen produced for the hydrogenation process through the steam reforming, partial oxidization and so on, of naphtha (although not strictly a byproduct, surplus production can occur and is therefore classified as byproduct hydrogen)

Figure 2.7.1. shows the domestic production capability and supply capacity of each byproduct hydrogen category.



Domestic hydrogen production ability :
238,3 [10^8Nm^3/year] (NEDO [2001-1])

from salt electrolysis 13.6 [10^8Nm^3/year]
from coke oven gas refining 88.7 [10^8Nm^3/year]
from petroleum industry 136.0 [10^8Nm^3/year]

Domestic hydrogen supply ability :
92.7 [10^8Nm^3/year] (NEDO [2001-1])

from salt electrolysis 12.4 [10^8Nm^3/year]
* value taken sold hydrogen from hydrogen production calculated from caustic soda production

from coke oven gas refining 53.2 [10^8Nm^3/year]
* 60% recover rate is considered as supply ability

from petroleum industry 27.1[10^8Nm^3/year]
* hydrogen from surplus production of facilities

Figure 2.7.1 Domestic production capability and supply availability of byproduct hydrogen

(3) Hydrogen Production by Water Electrolysis

Water electrolysis is a method of producing hydrogen through the electrolysis of water. The electrolysis efficiency of the solid polymer electrolyte membrane, also used in fuel cells, is drawing attention, and a field test for a solid polymer electrolyte membrane electrolysis-hydrogen refueling station has been conducted (NEDO [2001-1]). In addition, through the development of a reversible cell, namely an electrolysis cell that can function as a fuel cell, an attempt has been made, by the solid polymer electrolyte membrane electrolysis-hydrogen refueling station, to generate the additional value of power load equalization through hydrogen production using surplus power (IAE [2002]).

Other methods include the thermolysis (IS Process) process, currently being researched by the Japan Atomic Energy Research Institute (JAERI) from the perspective of utilizing heat supplied from high temperature gas reactors.

※ Properties of hydrogen

The properties of hydrogen applied in this study are as follows.

Chemical symbol	H
Atomic weight	1.00794 —
Molecular weight	2.0158 —
Density at normal condition	0.08989 kg/m^3
[Triple point]	
Temperature	13.803 K
	-259.347 ℃
Pressure	0.0704 bar
Solid staturation density	86.48 kg/m^3
Liquid staturation density	77.019 kg/m^3
Gas staturation density	0.1256 kg/m^3
Latent heat of fusion	58.2 kJ/kg
Latent heat of evaporation	449 kJ/kg
[Boiling point at atmospheric pressure]	
Temperature	20.268 K
	-252.882 ℃
Latent heat of evaporaion	446 kJ/kg
Liquid saturation density	70.779 kg/m^3
Gas saturation density	1.3378 kg/m^3
[Critical point]	
Temperature	32.976 K
	-240.174 ℃
Pressure	12.928 bar
Density	31.426 kg/m^3
[Stable isotope (natural content)]	
H (protium)	99.9885 %
D (deuterium)	0.0115 %

[Explosive combustion]	
Explosive limit (air mixture, 20℃, 1atm)	4～75 %
Spontaneous ignition temperature (air mixture, 1atm)	570 ℃
Explosive limit (oxygen mixture, 20℃, 1atm)	4～94 %
Spontaneous ignition temperature (oxygen mixture, 20℃, 1atm)	560 ℃
Minimum ignition energy	0.02 mJ
Quenching distance (atmospheric, 1atm, normal temperature)	0.06 cm
Theoretic air/fuel weight ratio	34.3 —
Diffusion coefficient (atmospheric, 0℃, 1atm)	0.611 m^2/s
Higher heating value (0℃, 1atm)	12,790 kJ/m^3
Lower heating value (0℃, 1atm)	10,780 kJ/m^3
Standard enthalpy of formation (25℃, 1atm)	
H_2O (gaseous)	-241.82 kJ/mol
H	217.97 kJ/mol
H_2	0 kJ/mol
O_2	0 kJ/mol
Standard Gibbs energy of formation (25℃, 1atm)	
H_2O (gaseous)	-228.59 kJ/mol
H	203.26 kJ/mol
H_2	0 kJ/mol
O_2	0 kJ/mol
Standard entropy of formation (25℃, 1atm)	
H_2O (gaseous)	188.72 J/mol/K
H	114.6 J/mol/K
H_2	130.57 J/mol/K
O_2	205.03 J/mol/K

[Source] http://www.enaa.or.jp/WE-NET/phs/butsu.html

2.7.2 Procedures for data collection of unit process

Hydrogen production pathway flow examined in this study are shown in Figure 2.7.2 (onsite) and Figure 2.7.3 (offsite):

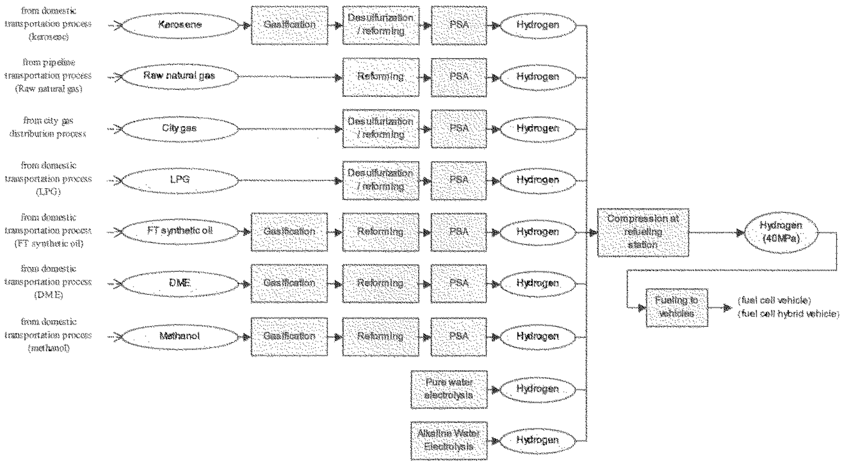

from domestic transportation process (kerosene)
Kerosene
Gasification
Desulfurization / reforming
PSA
Hydrogen
from pipeline transportation process (Raw natural gas)
Raw natural gas
Reforming
PSA
Hydrogen
from city gas distribution process
City gas
Desulfurization / reforming
PSA
Hydrogen
from domestic transportation process (LPG)
LPG
Desulfurization / reforming
PSA
Hydrogen
from domestic transportation process (FT synthetic oil)
FT synthetic oil
Gasification
Reforming
PSA
Hydrogen
from domestic transportation process (DME)
DME
Gasification
Reforming
PSA
Hydrogen
from domestic transportation process (methanol)
Methanol
Gasification
Reforming
PSA
Hydrogen
Pure water electrolysis
Hydrogen
Alkaline Water Electrolysis
Hydrogen
Compression at refueling station
Hydrogen (40MPa)
Fueling to vehicles
(fuel cell vehicle)
(fuel cell hybrid vehicle)

Figure 2.7.2 Pathway flow for on-site hydrogen production

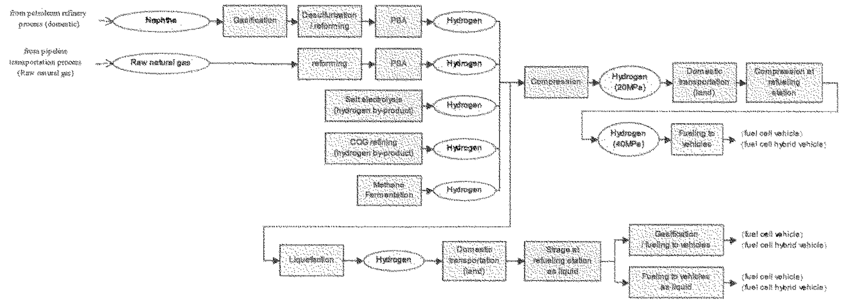

from petroleum refinery process (domestic)
Naphtha
Gasification
Desulfurization / reforming
PSA
Hydrogen
from pipeline transportation process (Raw natural gas)
Raw natural gas
reforming
PSA
Hydrogen
Salt electrolysis (hydrogen by-product)
Hydrogen
COG refining (hydrogen by-product)
Hydrogen
Methane Fermentation
Hydrogen
Compression
Hydrogen (20MPa)
Domestic transportation (land)
Compression at refueling station
Hydrogen (40MPa)
Fueling to vehicles
(fuel cell vehicle)
(fuel cell hybrid vehicle)
Liquefaction
Hydrogen
Domestic transportation (land)
Strage at refueling station as liquid
Gasification / fueling to vehicles
(fuel cell vehicle)
(fuel cell hybrid vehicle)
Fueling to vehicles as liquid
(fuel cell vehicle)
(fuel cell hybrid vehicle)

Figure 2.7.3 Pathway flow for off-site hydrogen production

The data calculation for the processes that compose these pathways are organized into (1) hydrogen production, (<i> steam reforming ((A) city gas reforming, (B) naphtha reforming, (C) methanol reforming, (D) gasoline reforming, (E) LPG reforming, (F) DME reforming, (G) reforming of kerosene and FT synthetic oil), <ii> coke oven gas (COG) refining, <iii> salt electrolysis, <iv> water electrolysis ((A) solid polymer electrolysis, (B) pure water electrolysis, (C) alkali water electrolysis, (D) packaged water electrolysis, (E) reversible cell pure water electrolysis), <v> CH_4 fermentation) + compression for storage & fueling/ compression or liquefaction for distribution, (2) transportation (compressed hydrogen transportation, liquefied hydrogen transportation), (3) storage & fueling.

Furthermore, regarding the "heating value of hydrogen supplied to a vehicle" required for energy efficiency calculations, in this study the FCV fuel tank is taken as the point of transfer of hydrogen, and for compressed hydrogen, the pressure energy required to compress hydrogen to 35 MPa or 40 MPa at 25 degrees C is added to the heating value of hydrogen at standard atmospheric pressure, as shown below:

$$E_{press} = R \times T_{H2} \times \ln\left(P_{H2}/P_0\right)$$

Where, R : gas constant (8.3151 [$Jmol^{-1}K^{-1}$])
T_{H2} : temperature of hydrogen (298.15 [K])
P_{H2} : standard atmospheric pressure (101.325 [kPa])
P_0 : pressure of gaseous hydrogen (35,000 [kPa])

In addition, as for liquefied hydrogen, as information related to the specific heat for hydrogen at 20 K (gas) could not be obtained, for energy efficiency calculations, the heating value of hydrogen at standard atmospheric pressure was also applied to liquefied hydrogen.

Table 2.7.1 Heating values of compressed hydrogen used in this study

		HHV	LHV
Atmospheric pressure (25℃)	MJ/kg	142.3	119.9
	MJ/Nm^3	12.79	10.78
20 MPa (25℃)	MJ/kg	148.8	126.4
	MJ/Nm^3	13.37	11.36
35 MPa (25℃)	MJ/kg	149.5	127.1
	MJ/Nm^3	13.44	11.43
40 MPa (25℃)	MJ/kg	149.6	127.3
	MJ/Nm^3	13.45	11.44

For energy consumption and GHG emissions calculations for each process from hydrogen production to supply to vehicle, conversion to energy consumption [MJ] at the point where electricity as energy input is consumed is calculated as 1 kWh = 3.6 MJ and CO_2 emissions are treated as zero, with increases in these values given separately depending on the electricity source (e.g. thermal, nuclear, biomass). This is because these values differ according to the electricity source (e.g. thermal, nuclear, biomass).

(1) Hydrogen Production + Compression for Storage & Fueling / Compression or Liquefaction for Distribution

<i> Steam Reforming

In many cases, hydrogen production through hydrocarbon reforming consists of the following two processes:

Reforming process	· A process to generate hydrogen by means of reforming reactions such as steam reforming and partial oxidation. · This term will comprehend not only reforming reaction itself but also accompanying reactions such as an aqueous reaction in which byproduct CO generated by reforming reaction is further reformed to hydrogen. (This definition applies to this study.)
Refining process	· A process to purify hydrogen from hydrogen-contained gas obtained from reforming process. · Methods to be used for refining process include membrane separation, cryogenic separation, pressure swing absorption (PSA), and so on.

The source of CO_2 emissions generated through hydrocarbon reforming is as follows:

- CO_2 derived from fuel (fossil fuel, electricity)
- CO_2 derived from feedstock (hydrocarbons)

CO_2 derived from feedstock refers to the carbon content discharged as CO_2 from the hydrocarbon used as hydrogen feedstock. In this study, calculations for CO_2 emissions from feedstock also use the CO_2 emission factors during combustion given in Table 1.3. This is because theoretically, all carbon content in the hydrocarbon is converted to CO_2 regardless of the applied reforming process, and the resulting CO_2 is considered to be equivalent to CO_2 emissions attributed to the complete combustion of the hydrocarbon. An example is given below.

- Steam reforming:

[reforming reaction] $C_nH_m + nH_2O \rightarrow nCO + (n+m/2)\,H_2$

[aqueous reaction] $nCO + nH_2O \rightarrow nH_2 + nCO_2$

From hydrocarbon C_nH_m 1 mol, n mol CO_2 is generated. Although there are cases where, after the reforming reaction, part of the gas containing hydrogen ($nCO+ (n+m/2)\,H_2$) is not directed to the water reaction and is used as fuel for the reforming reaction, in this case also, all CO is converted to CO_2 and overall CO_2 generation is n mol from C_nH_m 1 mol.

- Partial oxidation:

[partial oxidation] $C_nH_m + nO_2 \rightarrow nCO_2 + m/2\,H_2$

(A) City gas reforming

Prior studies related to hydrogen production through city gas reforming include the "Hydrogen Utilization – International Clean Energy Systems Technology (WE-NET)" conducted by NEDO. Calculations in this study are also based on WE-NET.

Two sets of data are calculated here, current status data based on specifications provided in the feasibility study for a 100 Nm^3/h, 300 Nm^3/h, 500 Nm^3/h class hydrogen station, NEDO [2002-1] (p.17), and updated data in which improvements in reforming efficiency (70%→80%) shown in NEDO [2003-1] (p. 64-65) are reflected in the current status data.

Regarding the allocation of power consumption other than for reforming/refining, values given in NEDO [2003-1] for a 300 Nm^3/h case have been used.

City gas input into the process has two different roles, one as the feedstock for hydrogen and the other as the heat source for the reforming reaction, and the ratio between these two roles is reported to be Feedstock: Fuel = 4.2: 0.2 (Tabata [2002]). However, as variations in this ratio may occur due to the size of reformer, and as the values calculated in this study for energy consumption, GHG emissions and energy efficiency do not vary, the total city gas input is treated as feedstock in this study.

Moreover, the properties of the hydrogen produced are 0.8 MPa, purity above 99.99 %, and for impurities, less than 10 ppm CO and less than 100 ppm CO_2 (NEDO [2002-1], [2002-2]).

(B) Naphtha reforming

Although much reference data is available for hydrogen production through naphtha reforming, as this method was established in the refinery and petrochemical industries long before hydrogen production for FCVs, the availability of reliable data is limited. Of these, this study selected the highly reliable studies of Nakajima *et al.* [1993], PEC [2003], NEDO [1995] and Japan Hydrogen & Fuel Cell Demonstration Project (JHFC) [2004] for reference.

B-1) Nakajima, *et al.* [1993]

There is a hydrogen production process using naphtha steam reforming known as the Topsøe method, developed by Denmark's Haldor Topsøe A/S. The company that the authors of this report belong to, the Chiyoda Corporation, had already established 20 facilities using this method in Japan and 5 facilities abroad by 1991. At the time, there were 136 such facilities worldwide.

B-2) PEC [2003]

This refers to a case where the PSA process was added on to the petrochemical industry's 1 million Nm^3/day class hydrogen production device.

Preconditions for inventory data calculation are taken from feedstock and utilities data for the hydrogen production device given in PEC [2003].

B-3) NEDO [1995]

While the process in Nakajima *et al.* [1993] and PEC [2003] obtains hydrogen through PSA refining after naphtha steam reforming, the process in NEDO [1995] obtains hydrogen through the partial oxidization of naphtha and aqueous reaction. Although the data in NEDO [1995] pertains to the hydrogen production process in oil refineries and petrochemical plants, there is also a statement saying "this data was created through surveys as publications regarding the production of hydrogen could not be obtained", and it is unclear whether the given values are from hearing surveys or from calculations based on assumptions.

B-4) JHFC [2004]

JHFC [2004] (p. 35-36) provides field test results for the Yokohama-Asahi Hydrogen Station. Calculations here are based on data for 50 Nm^3/h capacity reformers during rated operation.

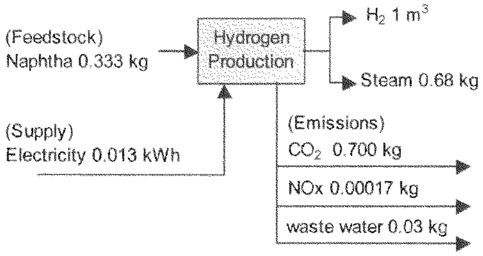


Figure 2.7.4 Hydrogen production process by NEDO [1995]

(C) Methanol reforming

Regarding hydrogen production through methanol reforming, NEDO [2001-3] provides diagrams and process specifications in relation to the high-purity hydrogen production method, with an established commercial performance record, owned by the Mitsubishi Gas Chemical Company, Inc. (MGC). In addition, JHFC [2004] provides field test results for the Kawasaki Hydrogen Station. This study focuses on these two cases.

C-1) NEDO [2001-3]

The MGC has an established commercial performance record for the on-site generation of high-purity hydrogen from methanol, using a combination of steam reforming and PSA.

Methanol steam reforming is conducted in a cracking reactor at an ambient temperature of 240-290 degrees C in the presence of a copper based catalyst. Steam is removed from the resulting hydrogen compound gas using coolers and steam-water separators, and the gas is refined into high-purity hydrogen gas through PSA separation/refining apparatus.

Pre-conditions for inventory data calculation are taken from high-purity hydrogen production process specifications given in NEDO [2001-3] (p. II-32).

C-2) JHFC [2004]

JHFC [2004] (p.37-38) provides field test results for the Kawasaki Hydrogen Station. Calculations here are based on data for 50 Nm^3/h capacity reformers during rated operation.

(D) Gasoline reforming

Regarding hydrogen production through gasoline reforming, JHFC [2004] (p.34-35) provides field test results for desulfurized gasoline at the Yokohama-Daikoku Hydrogen Station. Calculations here are based on data for 30 Nm^3/h capacity reformers during rated operation

(E) LPG reforming

Regarding hydrogen production through LPG reforming, NEDO [2001-3] provides examples of trial calculations made by applying the naphtha reforming model of Nakajima *et al.* [1993] to LPG. In addition, JHFC [2004] provides field test results for the Senju Hydrogen Station, Tokyo. This study focuses on these two cases.

E-1) NEDO [2001-3]

NEDO [2001-3] (p.II-31) conducts trial calculations for energy balance (desk study) when the naphtha reforming model of Nakajima *et al.* [1993] is applied to LPG.

E-2) JHFC [2004]

JHFC [2004] (p.36-37) provides field test results for the Senju Hydrogen Station. Calculations here are based on data for 50 Nm^3/h capacity reformers during rated operation.

(F) DME reforming

The hydrogen production system through DME reforming given in NEDO [2001-3] (p. II -33) is fundamentally the same as the methanol fueled system, and assumes a steam reforming reaction taking place in the presence of a catalyst at temperatures between 250-450 degrees C.

NEDO [2001-3] estimates DME reforming efficiency based on these assumptions. Specifically, based on reference materials related to the methanol reforming hydrogen production device of MGC mentioned in C-1) of this study, the material balance for the DME steam reforming reaction is estimated, and reforming efficiency is also assessed through trial calculations per unit utility. Here, DME reactivity (excluding temperature) and PSA hydrogen separation efficiency is considered equivalent to a methanol plant.

(G) Kerosene / FT synthetic oil reforming

Data related to hydrogen production through the reforming of kerosene and FT synthetic oil could not be obtained for this study. Consequently, using data related to hydrogen production through the reforming of naphtha and desulfurized gasoline, given in JHFC [2004] for reference, resources required for the production of 1 kg hydrogen were assumed to be 4.8 kg kerosene or FT synthetic oil, and 7 kWh electricity.

<ii> Hydrogen Production through COG Refining

Other than hydrogen, rest gas (fuel gas that does not contain hydrogen) is produced during the separation and refining process. Hydrogen can also be recovered from byproduct gases such as coke oven gas (COG), blast furnace gas (BFG) and Linz-Donawitz converter gas (LDG), produced in new iron and steel manufacturing processes. Of these, COG has the highest hydrogen ratio.

COG contains more than 50 % hydrogen, and high purity hydrogen can be recovered with ease following the removal of impurities and PSA refining. Regarding hydrogen production through COG refining, this study calculates energy consumption and GHG emissions based on data given in NEDO [2002-1]. Although data related to hydrogen production through COG refining is also given in PEC [2003], the source for this data is NEDO [2002-1], and the two are basically the same. Furthermore, this study does not take energy consumption and GHG emissions during the production of the COG feedstock into consideration.

In the process of hydrogen production through COG refining, other than hydrogen, REST gas (fuel gas that does not contain hydrogen) is produced during the PSA separation and refining of hydrogen contained in the COG. Although NEDO [2002-1] (p.10) provides specifications for five cases of average hydrogen production capacity (556 Nm^3/h, 1,669 Nm^3/h, 5,562 Nm^3/h, 16,685 Nm^3/h, 55,617 Nm^3/h), as the feedstock / utility consumption for 16,685 Nm^3/h and 55,617 Nm^3/h is equal to that of 5,562 Nm^3/h, these have been omitted from this study.

<iii> Hydrogen Derived from Caustic Soda Production through Salt Electrolysis

One method of hydrogen supply involves the utilization of byproduct hydrogen derived from caustic soda production through salt electrolysis. As the main objective of this process is the production of caustic soda, the environmental burden generated here is considered non-attributable to hydrogen. However, in cases where this hydrogen is already utilized as a heat source, as extra energy will be required to supplement this usage, usage of byproduct hydrogen can be misjudged unless some manner of environmental burden is considered for byproduct hydrogen.

Regarding the salt electrolysis process, data given in Plastic Waste Management Institute (PWMI) [1993] is frequently cited. By using the product (NaOH, chlorine, hydrogen) weight composition ratio to distribute burden data given in PWMI [1993], it is possible to apportion environmental burden to byproduct hydrogen from salt electrolysis, however, for this study, processes related to byproduct hydrogen production through salt electrolysis are treated as beyond the sphere of the system.

<iv> Hydrogen Production through Water Electrolysis

Although hydrogen production through water electrolysis is an important industrial hydrogen production method, this method has not gained much attention in Japan, as the production of hydrogen directly from carbonaceous fuel resources is cheaper in comparison. However, with the WE-NET concept of hydrogen production through water electrolysis using cheap overseas hydroelectric power, this technology has been reviewed, and technological development in this field is progressing.

In this study, energy consumption and GHG emissions calculations regarding hydrogen production through water electrolysis are based on specifications for the solid polymer electrolysis hydrogen production device currently marketed by Hitachi Zosen Corporation (HITZ), and data given in NEDO [2003-1] and IAE other [2002].

(A) On-site water electrolysis hydrogen production device (Hitachi Zosen Corporation)

The on-site water electrolysis hydrogen production device of the HITZ is a highly efficient system using a solid polymer water electrolysis cell, which achieves on-site hydrogen production without using any alkalis or other chemical solutions. There are three levels of hydrogen production capability (0.5 Nm^3/h, 1.0 Nm^3/h, 3.0 Nm^3/h) and each is currently marketed. Data calculations are based on the specifications for these water electrolysis hydrogen production devices.

(B) Pure water electrolysis hydrogen production device (NEDO [2003-1])

Energy consumption and GHG emissions for hydrogen production through pure water electrolysis are calculated from data given in NEDO [2003-1]. Although facility scale is from 100-500 Nm^3/h, power and utility consumption per unit is fixed.

(C) Alkali water electrolysis hydrogen production device (NEDO [2003-1])

Energy consumption and GHG emissions for hydrogen production through alkali water electrolysis are calculated from data given in NEDO [2003-1].

(D) Packaged water electrolysis hydrogen production device (NEDO [2003-1])

Energy consumption and GHG emissions for hydrogen production using packaged pure water electrolysis and packaged alkali water electrolysis devices are calculated from data given in NEDO [2003-1].

(E) Hydrogen production using reversible cell device (IAE [2002])

IAE other [2002] introduces a pure water electrolysis device, which uses reversible cells (reversible cell stack capable of water electrolysis and fuel cell operation) as a power load equalization system for installation into buildings. Calculations for energy consumption and GHG emissions for hydrogen production using this reversible cell were conducted using specification data (calculations based on assumptions) for hydrogen/air systems provided in IAE other [2002] for reference.

From the above, 4.3-6.2 kWh was derived for energy consumption during the production of 1 Nm^3 hydrogen. In general, energy consumption for 1 Nm^3 hydrogen through water electrolysis is said to be 4.5-6.2 kWh (Ishiguro [1981]), 4.8-5.3 kWh (Electrochemical Society of Japan (ECSJ) [2000]), and the value indicated in (E) (4.3 kWh) (based on assumption) is an estimated value for ideal conditions. In addition, (A) (5.5-6.0 kWh) is for an actual device, and is considered an appropriate value taking into account the comparatively small size of the device.

<v> Hydrogen Production through CH_4 Fermentation

In this study, hydrogen production through CH_4 fermentation is treated as equivalent to hydrogen production through city gas reforming (see "<i> (A) City gas reforming").

<vi> Compression for Storage & Fueling/ Compression or Liquefaction for Distribution

For hydrogen transportation or supply to FCVs, it is necessary to increase energy density through compression or liquefaction. Here, process data is calculated in relation to compression or liquefaction for transportation purposes when hydrogen is produced off-site.

(A) Compression for distribution (0.8 MPa → 19.6 MPa)

Calculations are based on data given in NEDO [2002-1] (p.11) for a 556-55,617 Nm^3/h class off-site hydrogen station. Furthermore, this data is for the transportation process of pure hydrogen, obtained from COG refining, for delivery to an off-site hydrogen refueling station as compressed hydrogen.

Regarding the pressure of compressed hydrogen, this study uses the value, 19.6 MPa, given in NEDO [2003-1] (p.56).

(B) Liquefaction for distribution (0.8 MPa → 0.0708 kg/L)

Calculations are based on data given in NEDO [2002-1] (p.12) for a 556-55,617 Nm^3/h class off-site hydrogen station. Furthermore, this data is for the transportation process of pure hydrogen, obtained from COG refining, for delivery to an off-site hydrogen refueling station as liquefied hydrogen.

(2) Transportation (Compressed / Liquefied)

<i> Transportation of Compressed Hydrogen

NEDO [2003-1] (p.56) states, "transportation of compressed hydrogen from an off-site hydrogen production plant to a station will be in hydrogen trailers carrying multiple long copper containers, towed by a tractor". According to the same document, for a trailer carrying 22 * 715 L containers, the disposable load is 2,460 Nm^3/vehicle. This study also uses this data. The tractor fuel consumption value of 3km/L-diesel, given in NEDO [2000] (p.45), was adopted.

In addition, assuming transportation to prefectures in the Kanto area, shipping distance was set at a round trip value of 100 km.

<ii> Transportation of Liquefied Hydrogen

Calculations for energy consumption and GHG emissions during transportation of liquefied hydrogen are based on the liquefied hydrogen load value, 14,561 Nm^3/vehicle (lorry), given in NEDO [2002-1] (p.15) and the fuel consumption value, 2.2km/L-diesel (lorry), given in JHFC [2004] (p.90).

In addition, assuming transportation to prefectures in the Kanto area, shipping distance was set at a round trip value of 100 km.

(3) Storage & Fueling

<i> High Pressure Fueling of Compressed Hydrogen (19.6 MPa)

NEDO [2002-1] (p.16) provides data related to three examples of off-site hydrogen station, 100 Nm^3/h, 300

Nm^3/h, 500 Nm^3/h (high-pressure storage & high-pressure fueling, average 10 MPa → 40 MPa), regarding the further compression of compressed hydrogen shipped by trailer for high-pressure fueling of FCVs. In addition, JHFC [2004] (p.38) provides field test results for a mobile hydrogen station (19.6 MPa → 35 MPa). For this study, the values given in JHFC [2004], which are close to actual values, were used.

(A) NEDO [2002-1]

The power consumed during high-pressure refueling of compressed hydrogen to a FCV, calculated based on specifications provided in NEDO [2002-1] (p.16) for high-pressure storage & high-pressure fueling stations, is 0.12-0.15 kWh/Nm^3-H_2.

(B) JHFC [2004]

Calculations are based on data given in JHFC [2004] (p.38). Here, the pressure of compressed hydrogen supplied to a FCV is 35 MPa.

<ii> High Pressure Fueling of Liquefied Hydrogen (0.0708 kg/L)

In this process, the liquefied hydrogen is stored as liquefied hydrogen and supplied through high-pressure fueling to a FCV as compressed hydrogen (40 MPa). NEDO [2002-1] (p.16) provides data related to three examples of off-site hydrogen station, 100 Nm^3/h, 300 Nm^3/h, 500 Nm^3/h (liquefied storage & high-pressure fueling, average 0.0708 kg/L→40 MPa), regarding this process. Here, data calculated based on specifications for liquefied storage – high-pressure fueling stations, provided in NEDO [2002-1] (p.16), is used.

<iii> Fueling as Liquefied Hydrogen (0.0708 kg/L)

In this process, the liquefied hydrogen is stored as liquefied hydrogen and supplied to a FCV without change during fueling. NEDO [2002-1] (p.17) provides data related to three examples of off-site hydrogen station, 100 Nm^3/h, 300 Nm^3/h, 500 Nm^3/h (liquefied storage & liquefied fueling, average 0.0708 kg/L→40 MPa), regarding this process. Here, data calculated based on specifications for liquefied storage & liquefied fueling stations, provided in NEDO [2002-1] (p.17), is used.

2.7.3 Calculation results

The calculation results for hydrogen production pathways are indicated separately for on-site (hydrocarbon reforming, on-site water electrolysis) and off-site (compressed hydrogen transportation → compressed hydrogen fueling, liquefied hydrogen transportation → compressed hydrogen fueling, liquefied hydrogen transportation → liquefied hydrogen fueling).

Regarding the no-site hydrocarbon reforming, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.7.2 (energy consumption), Table 2.7.3 (GHG emissions) and Table 2.7.4 (energy efficiency).

Table 2.7.2（A） WTT energy consumption of hydrogen production pathways [MJ/MJ]
(on-site hydrocarbon reforming (city gas, petroleum products))

	City gas reforming				Desulfurized gasoline reforming	Kerosene reforming	LPG reforming					
	From LNG		From pipeline				From raw natural gas		From associated gas		From petroleum refinery	
	(Conventional)	(Improved)	(Conventional)	(Improved)			(NEDO)	(JHC)	(NEDO)	(JHC)	(NEDO)	(JHC)
Feedstock production	0.23	0.20	0.11	0.09	0.33	0.11	0.24	0.27	0.18	0.20	0.23	0.25
H2 production (reforming)	0.08	0.08	0.08	0.08	0.11	0.09	0.33	0.05	0.33	0.05	0.33	0.05
Compression/fueling	0.09	0.09	0.09	0.09	0.10	0.12	0.09	0.15	0.09	0.15	0.09	0.15
Total (*1)	0.40	0.37	0.28	0.27	0.54	0.32	0.66	0.46	0.60	0.39	0.64	0.44
Additional energy consumption to generate 1kWh=3.6MJ electric power by means of power generation [MJ/MJ-H2]												
(Petroleum)	+0.33	+0.33	+0.33	+0.33	+0.41	+0.42	+0.24	+0.38	+0.24	+0.38	+0.24	+0.38
(LNG)	+0.32	+0.32	+0.32	+0.32	+0.40	+0.40	+0.24	+0.38	+0.24	+0.38	+0.24	+0.38
(LNG combined)	+0.24	+0.24	+0.24	+0.24	+0.29	+0.30	+0.18	+0.28	+0.18	+0.28	+0.18	+0.28
(Coal)	+0.30	+0.30	+0.30	+0.30	+0.37	+0.37	+0.22	+0.35	+0.22	+0.35	+0.22	+0.35
(Japan average) (*2)	+0.32	+0.32	+0.32	+0.32	+0.39	+0.39	+0.24	+0.37	+0.24	+0.37	+0.24	+0.37
(*1)+(*2)	0.72	0.69	0.60	0.59	0.93	0.72	0.90	0.83	0.83	0.76	0.88	0.81

Table 2.7.2（B） WTT energy consumption of hydrogen production pathways [MJ/MJ]
(on-site hydrocarbon reforming (synthetic fuels))

	FT synthetic oil reforming					DME reforming		Methanol reforming			
	From natural gas	From coal		From biomass		From natural gas	From biomass	From natural gas		From biomass	
		(best)	(worst)	(best)	(worst)			(best)	(worst)	(best)	(worst)
Feedstock production	0.97	1.70	2.04	1.85	2.33	0.58	1.07	0.56	0.79	0.70	1.32
Hydrogen production (reforming)	0.09	0.09	0.09	0.09	0.09	0.21	0.21	0.17	0.24	0.17	0.24
Compression / fueling	0.12	0.12	0.12	0.12	0.12	0.09	0.09	0.09	0.08	0.09	0.08
Total (*1)	1.18	1.91	2.25	2.06	2.54	0.89	1.37	0.83	1.11	0.97	1.64
Additional energy consumption to generate 1kWh=3.6MJ electric power by means of power generation [MJ/MJ-H_2]											
(Petroleum)	+0.41	+0.41	+0.41	+0.41	+0.41	+0.23	+0.23	+0.21	+0.63	+0.21	+0.63
(LNG)	+0.40	+0.40	+0.40	+0.40	+0.40	+0.23	+0.23	+0.20	+0.62	+0.20	+0.62
(LNG combined)	+0.30	+0.30	+0.30	+0.30	+0.30	+0.17	+0.17	+0.15	+0.46	+0.15	+0.46
(Coal)	+0.37	+0.37	+0.37	+0.37	+0.37	+0.21	+0.21	+0.19	+0.58	+0.19	+0.58
(Japan average) (*2)	+0.39	+0.39	+0.39	+0.39	+0.39	+0.23	+0.23	+0.20	+0.61	+0.20	+0.61
(*1) + (*2)	1.58	2.31	2.64	2.46	2.94	1.11	1.60	1.03	1.72	1.17	2.25

Table 2.7.3 (A) WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(on-site hydrocarbon reforming (city gas, petroleum products))

	City gas reforming				Desulfurized gasoline reforming	Kerosene reforming	LPG reforming					
	From LNG		From pipeline				From raw natural gas		From associated gas		From petroleum refinery	
	(Conventional)	(Improved)	(Conventional)	(Improved)			(NEDO)	(JHFC)	(NEDO)	(JHFC)	(NEDO)	(JHFC)
Feedstock production	17.1	14.9	6.6	5.7	21.4	8.1	18.4	20.2	11.6	12.7	14.9	16.3
H2 production / Compression												
CO2 from feedstock	83.3	72.3	83.3	72.3	129.6	125.9	95.4	104.5	95.4	104.5	95.4	104.5
Total (*1)	100.4	87.2	89.8	78.0	151.0	134.0	113.8	124.7	107.0	117.2	110.2	120.8
Additional GHG emission to generate 1kWh=3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H_2]												
(Petroleum)	+37.0	+37.0	+37.0	+37.0	+45.4	+45.7	+27.2	+42.8	+27.2	+42.8	+27.2	+42.8
(LNG)	+29.8	+29.8	+29.8	+29.8	+36.6	+36.8	+22.0	+34.5	+22.0	+34.5	+22.0	+34.5
(LNG combined)	+24.4	+24.4	+24.4	+24.4	+30.0	+30.2	+18.0	+28.3	+18.0	+28.3	+18.0	+28.3
(Coal)	+46.3	+46.3	+46.3	+46.3	+56.9	+57.2	+34.1	+53.6	+34.1	+53.6	+34.1	+53.6
(Japan average) (*2)	+21.0	+21.0	+21.0	+21.0	+25.7	+25.9	+15.4	+24.2	+15.4	+24.2	+15.4	+24.2
(*1)+(*2)	121.3	108.1	110.8	99.0	176.7	159.9	129.2	148.9	122.4	141.4	125.6	145.0

Table 2.7.3 (B) WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(on-site hydrocarbon reforming (synthetic fuels))

	FT synthetic oil reforming					DME reforming		Methanol reforming			
	From natural gas	From coal		From biomass		From natural gas	From biomass	From natural gas		From biomass	
		(best)	(worst)	(best)	(worst)			(best)	(worst)	(best)	(worst)
Feedstock production	40.5	117.6	120.0	14.2	15.8	21.4	11.1	24.6	35.9	10.7	14.8
Hydrogen production / Compression								12.1		12.1	
CO2 from feedstock	125.9	125.9	125.9	1.3	1.3	96.9	14.1	74.0	92.4		
Total (*1)	166.4	243.5	245.9	15.5	17.1	118.3	25.1	110.7	128.3	22.8	14.8
Additional GHG emission to generate 1kWh = 3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H_2]											
(Petroleum)	+45.7	+45.7	+45.7	+45.7	+45.7	+26.1	+26.1	+23.2	+70.6	+23.2	+70.6
(LNG)	+36.8	+36.8	+36.8	+36.8	+36.8	+21.1	+21.1	+18.7	+57.0	+18.7	+57.0
(LNG combined)	+30.2	+30.2	+30.2	+30.2	+30.2	+17.3	+17.3	+15.3	+46.7	+15.3	+46.7
(Coal)	+57.2	+57.2	+57.2	+57.2	+57.2	+32.7	+32.7	+29.1	+88.5	+29.1	+88.5
(Japan average) (*2)	+25.9	+25.9	+25.9	+25.9	+25.9	+14.8	+14.8	+13.2	+40.0	+13.2	+40.0
(*1) + (*2)	192.3	269.4	271.8	41.4	43.0	133.1	39.9	123.8	168.3	35.9	54.8

Table 2.7.4 (A) WTT energy efficiency of hydrogen production pathways (LHV)
(on-site hydrocarbon reforming (city gas, petroleum products))

	City gas reforming				Desulfurized gasoline reforming	Kerosene reforming	LPG reforming					
	From LNG		From pipeline				From raw natural gas		From associated gas		From petroleum refinery	
	(Conventional)	(Improved)	(Conventional)	(Improved)			(NEDO)	(JHFC)	(NEDO)	(JHFC)	(NEDO)	(JHFC)
Feedstock production	0.863	0.863	0.934	0.934	0.830	0.924	0.853	0.853	0.889	0.889	0.916	0.916
H2 production (reforming)	0.650	0.743	0.650	0.743	0.536	0.555	0.654	0.591	0.654	0.591	0.654	0.591
Compression / fueling	0.971	0.971	0.971	0.971	0.968	0.949	0.971	0.925	0.971	0.925	0.971	0.925
Total (*1)	0.545	0.622	0.590	0.674	0.431	0.486	0.541	0.467	0.565	0.486	0.582	0.501
Energy efficiency to generate 1kWh=3.6MJ electric power by means of power generation (LHV)												
(Petroleum)	0.358											
(LNG)	0.354											
(LNG combined)	0.422											
(Coal)	0.386											
(Japan average) (*2)	0.348											

Table 2.7.4 (B) WTT energy efficiency of hydrogen production pathways (LHV)
(on-site hydrocarbon reforming (synthetic fuels))

	FT synthetic oil reforming					DME reforming		Methanol reforming			
	From natural gas	From coal		From biomass		From natural gas	From biomass	From natural gas		From biomass	
		(best)	(worst)	(best)	(worst)			(best)	(worst)	(best)	(worst)
Feedstock production	0.638	0.508	0.463	0.489	0.431	0.671	0.536	0.640	0.613	0.597	0.496
Hydrogen production (reforming)	0.555	0.555	0.555	0.555	0.555	0.687	0.687	0.804	0.632	0.804	0.632
Compression / fueling	0.949	0.949	0.949	0.949	0.949	0.971	0.971	0.971	0.979	0.971	0.979
Total (*1)	0.336	0.267	0.244	0.257	0.227	0.447	0.357	0.500	0.379	0.466	0.307
Energy efficiency to generate 1kWh = 3.6MJ electric power by means of power generation (LHV)											
(Petroleum)	0.358										
(LNG)	0.354										
(LNG combined)	0.422										
(Coal)	0.386										
(Japan average) (*2)	0.348										

Regarding the on-site water electrolysis, the results of calculations for energy consumption, GHG emissions and energy efficiency during production of 1 MJ petroleum products are shown in Table 2.7.5 (energy consumption), Table 2.7.6 (GHG emissions) and Table 2.7.7 (energy efficiency).

Table 2.7.5 WTT energy consumption of hydrogen production pathways [MJ/MJ]
(on-site water electrolysis)

	PEFC (Hitachi Zosen)			Pure water electrolysis	Alkali water electrolysis			Package type		Pure water electrolysis using reversible cell		
	HS2505	HS2510	HS2530		KOH100	KOH300	KOH500	PA-P	PA-K	40kW	500kW	1000kW
Hydrogen production (electrolysis)	2.00	1.84	1.84	1.50	1.78	1.64	1.65	2.07	1.60	1.44	1.44	1.44
Compression / fueling	↑	↑	↑	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Total (*1)	2.00	1.84	1.84	1.60	1.87	1.73	1.74	2.16	1.70	1.54	1.53	1.53
Additional energy consumption to generate 1kWh = 3.6MJ electric power by means of power generation [MJ/MJ-H_2]												
(Petroleum)	+3.90	+3.57	+3.57	+3.11	+3.65	+3.37	+3.39	+4.21	+3.30	+2.99	+2.98	+2.98
(LNG)	+3.82	+3.50	+3.50	+3.05	+3.57	+3.30	+3.33	+4.13	+3.24	+2.93	+2.92	+2.92
(LNG combined)	+2.83	+2.59	+2.59	+2.25	+2.64	+2.44	+2.46	+3.05	+2.39	+2.16	+2.16	+2.16
(Coal)	+3.55	+3.25	+3.25	+2.83	+3.32	+3.07	+3.09	+3.83	+3.01	+2.72	+2.71	+2.71
(Japan average) (*2)	+3.76	+3.45	+3.45	+3.00	+3.52	+3.25	+3.27	+4.06	+3.18	+2.88	+2.88	+2.88
(*1) + (*2)	5.77	5.28	5.28	4.59	5.39	4.98	5.02	6.23	4.88	4.42	4.41	4.41

Table 2.7.6 WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(on-site water electrolysis)

	PEFC (Hitachi Zosen)			Pure water electrolysis	Alkali water electrolysis			Package type		Pure water electrolysis using reversible cell		
	HS2505	HS2510	HS2530		KOH100	KOH300	KOH500	PA-P	PA-K	40kW	500kW	1000kW
Hydrogen production (electrolysis)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compression / fueling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (*1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additional GHG emission to generate 1kWh = 3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H_2]												
(Petroleum)	+435.4	+399.1	+399.1	+346.9	+407.1	+375.9	+378.8	+470.2	+368.6	+333.6	+332.8	+332.9
(LNG)	+351.1	+321.8	+321.8	+279.7	+328.3	+303.1	+305.4	+379.2	+297.2	+269.0	+268.4	+268.4
(LNG combined)	+287.5	+263.6	+263.6	+229.1	+268.9	+248.3	+250.2	+310.6	+243.5	+220.3	+219.8	+219.9
(Coal)	+545.3	+499.8	+499.8	+434.4	+509.8	+470.8	+474.4	+588.9	+461.7	+417.8	+416.8	+416.9
(Japan average) (*2)	+246.6	+226.0	+226.0	+196.4	+230.5	+212.9	+214.5	+266.3	+208.8	+188.9	+188.5	+188.5
(*1) + (*2)	246.6	226.0	226.0	196.4	230.5	212.9	214.5	266.3	208.8	188.9	188.5	188.5

Table 2.7.7 WTT energy efficiency of hydrogen production pathways (LHV)
(on-site water electrolysis)

	PEFC (Hitachi Zosen)			Pure water electrolysis	Alkali water electrolysis			Package type		Pure water electrolysis using reversible cell		
	HS2505	HS2510	HS2530		KOH100	KOH300	KOH500	PA-P	PA-K	40kW	500kW	1000kW
Hydrogen production (electrolysis)	0.499	0.544	0.544	0.665	0.562	0.611	0.606	0.483	0.624	0.694	0.695	0.695
Compression / fueling	↑	↑	↑	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.971
Total (*1)	0.499	0.544	0.544	0.646	0.545	0.593	0.588	0.469	0.606	0.673	0.675	0.675
Energy efficiency to generate 1kWh = 3.6MJ electric power by means of power generation (LHV)												
(Petroleum)	0.358											
(LNG)	0.354											
(LNG combined)	0.422											
(Coal)	0.386											
(Japan average) (*2)	0.348											

In relation to off-site handling, depending on transportation method and fueling method, three cases were considered (compressed hydrogen transportation → compressed hydrogen fueling, liquefied hydrogen transportation → compressed hydrogen fueling, liquefied hydrogen transportation → liquefied hydrogen fueling).

Calculation results for each process ((A) compressed hydrogen transportation → compressed hydrogen fueling, (B) liquefied hydrogen transportation → compressed hydrogen fueling, (C) liquefied hydrogen transportation → liquefied hydrogen fueling) for energy consumption, GHG emissions and energy efficiency during the production of 1MJ hydrogen, are shown in Table 2.7.8 (Energy Consumption), Table 2.7.9 (GHG Emissions) and Table 2.7.10 (Energy Efficiency).

Table 2.7.8（A） WTT energy consumption of hydrogen production pathways [MJ/MJ]
(compressed hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.12	0.14	0.11	0.15					0.10	0.08	0.85	0.74
Hydrogen production / refining	0.30	0.80	0.004	0.07	0.15	0.15	0.11		0.08	0.08	0.08	0.08
Compression for distribution	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Domestic transport	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Compression / fueling	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total (*1)	0.62	1.14	0.32	0.41	0.35	0.34	0.31	0.20	0.37	0.36	1.13	1.02
Additional energy consumption to generate 1kWh=3.6MJ electric power by means of power generation [MJ/MJ-H2]												
(Petroleum)	+0.31	+0.33	+0.31	+0.43	+0.59	+0.58	+0.51	+0.30	+0.45	+0.45	+0.45	+0.45
(LNG)	+0.30	+0.32	+0.30	+0.42	+0.58	+0.57	+0.50	+0.29	+0.44	+0.44	+0.44	+0.44
(LNG combined)	+0.22	+0.24	+0.22	+0.31	+0.43	+0.42	+0.37	+0.22	+0.32	+0.32	+0.32	+0.32
(Coal)	+0.28	+0.30	+0.28	+0.39	+0.54	+0.53	+0.47	+0.27	+0.41	+0.41	+0.41	+0.41
(Japan average) (*2)	+0.30	+0.32	+0.30	+0.42	+0.57	+0.56	+0.50	+0.29	+0.43	+0.43	+0.43	+0.43
(*1)+(*2)	0.92	1.45	0.61	0.83	0.92	0.90	0.80	0.49	0.80	0.79	1.56	1.45

Table 2.7.8（B） WTT energy consumption of hydrogen production pathways [MJ/MJ]
(liquefied hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.12	0.14	0.11	0.15					0.10	0.08	0.85	0.74
Hydrogen production / refining	0.30	0.80	0.004	0.07	0.15	0.15	0.11		0.08	0.08	0.08	0.08
Liquefaction for distribution	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Domestic transport	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Gasification / compression / fueling	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Total (*1)	0.86	1.38	0.55	0.66	0.59	0.58	0.55	0.44	0.61	0.60	1.37	1.25
Additional energy consumption to generate 1kWh=3.6MJ electric power by means of power generation [MJ/MJ-H2]												
(Petroleum)	+0.84	+0.86	+0.84	+0.96	+1.12	+1.11	+1.04	+0.83	+0.98	+0.98	+0.98	+0.98
(LNG)	+0.82	+0.84	+0.82	+0.94	+1.10	+1.09	+1.02	+0.81	+0.96	+0.96	+0.96	+0.96
(LNG combined)	+0.61	+0.62	+0.61	+0.70	+0.81	+0.81	+0.76	+0.60	+0.71	+0.71	+0.71	+0.71
(Coal)	+0.76	+0.78	+0.76	+0.88	+1.02	+1.01	+0.95	+0.75	+0.89	+0.89	+0.89	+0.89
(Japan average) (*2)	+0.81	+0.83	+0.81	+0.93	+1.08	+1.07	+1.01	+0.80	+0.94	+0.94	+0.94	+0.94
(*1)+(*2)	1.67	2.20	1.36	1.58	1.67	1.65	1.55	1.24	1.55	1.54	2.31	2.20

Table 2.7.8（C） WTT energy consumption of hydrogen production pathways [MJ/MJ]
(liquefied hydrogen transportation→liquefied hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.12	0.14	0.11	0.15					0.10	0.08	0.85	0.74
Hydrogen production / refining	0.30	0.80	0.004	0.07	0.15	0.15	0.11		0.08	0.08	0.08	0.08
Liquefaction for distribution	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Domestic transport	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Fueling as liquid	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total (*1)	0.81	1.32	0.50	0.60	0.53	0.53	0.49	0.38	0.55	0.54	1.31	1.20
Additional energy consumption to generate 1kWh=3.6MJ electric power by means of power generation [MJ/MJ-H2]												
(Petroleum)	+0.73	+0.75	+0.73	+0.86	+1.02	+1.00	+0.94	+0.72	+0.87	+0.87	+0.87	+0.87
(LNG)	+0.72	+0.74	+0.72	+0.84	+1.00	+0.99	+0.92	+0.71	+0.85	+0.85	+0.85	+0.85
(LNG combined)	+0.53	+0.54	+0.53	+0.62	+0.74	+0.73	+0.68	+0.52	+0.63	+0.63	+0.63	+0.63
(Coal)	+0.67	+0.68	+0.67	+0.78	+0.93	+0.92	+0.85	+0.66	+0.79	+0.79	+0.79	+0.79
(Japan average) (*2)	+0.71	+0.72	+0.70	+0.83	+0.98	+0.97	+0.90	+0.70	+0.84	+0.84	+0.84	+0.84
(*1)+(*2)	1.51	2.05	1.20	1.42	1.52	1.50	1.40	1.08	1.40	1.38	2.15	2.04

Table 2.7.9（A） WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(compressed hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	8.4	9.9	7.7	9.9					5.7	5.0	24.6	21.4
Hydrogen production / refining	20.7	54.8										
Compression for distribution												
Domestic transport	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Compression / fueling												
CO2 from feedstock	83.0	66.6	94.4	121.6					83.3	72.3		
Total (*1)	115.5	134.6	105.4	134.8	3.3	3.3	3.3	3.3	92.4	80.6	27.9	24.7
Additional GHG emission to generate 1kWh=3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H2]												
(Petroleum)	+34.4	+36.5	+34.3	+48.4	+66.4	+64.9	+57.3	+33.4	+50.1	+50.1	+50.1	+50.1
(LNG)	+27.7	+29.4	+27.7	+39.0	+53.5	+52.4	+46.2	+26.9	+40.4	+40.4	+40.4	+40.4
(LNG combined)	+22.7	+24.1	+22.7	+32.0	+43.9	+42.9	+37.9	+22.0	+33.1	+33.1	+33.1	+33.1
(Coal)	+43.1	+45.7	+43.0	+60.6	+83.2	+81.3	+71.8	+41.8	+62.7	+62.7	+62.7	+62.7
(Japan average) (*2)	+19.5	+20.7	+19.4	+27.4	+37.6	+36.8	+32.5	+18.9	+28.4	+28.4	+28.4	+28.4
(*1)+(*2)	135.0	155.3	124.9	162.2	40.9	40.1	35.8	22.2	120.7	109.0	56.3	53.0

Table 2.7.9（B） WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(liquefied hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	8.4	9.9	7.7	9.9					5.7	5.0	24.6	21.4
Hydrogen production / refining	20.7	54.8										
Liquefaction for distribution												
Domestic transport	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Gasification / compression / fueling												
CO2 from feedstock	83.0	66.6	94.4	121.6					83.3	72.3		
Total (*1)	112.9	132.0	102.9	132.2	0.8	0.8	0.8	0.8	89.8	78.1	25.4	22.1
Additional GHG emission to generate 1kWh=3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H_2]												
(Petroleum)	+93.5	+95.6	+93.4	+107.5	+125.5	+124.1	+116.4	+92.5	+109.2	+109.2	+109.2	+109.2
(LNG)	+75.4	+77.1	+75.3	+86.7	+101.2	+100.0	+93.9	+74.6	+88.0	+88.0	+88.0	+88.0
(LNG combined)	+61.7	+63.1	+61.7	+71.0	+82.9	+81.9	+76.9	+61.1	+72.1	+72.1	+72.1	+72.1
(Coal)	+117.1	+119.7	+117.0	+134.6	+157.2	+155.4	+145.8	+115.8	+136.7	+136.7	+136.7	+136.7
(Japan average) (*2)	+53.0	+54.1	+52.9	+60.9	+71.1	+70.3	+65.9	+52.4	+61.8	+61.8	+61.8	+61.8
(*1)+(*2)	165.9	186.2	155.8	193.1	71.8	71.0	66.7	53.1	151.6	139.9	87.2	84.0

Table 2.7.9（C） WTT GHG emissions of hydrogen production pathways [g eq-CO_2/MJ]
(liquefied hydrogen transportation→liquefied hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsoe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	8.4	9.9	7.7	9.9					5.7	5.0	24.6	21.4
Hydrogen production / refining	20.7	54.8										
Liquefaction for distribution												
Domestic transport	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Fueling as liquid												
CO2 from feedstock	83.0	66.6	94.4	121.6					83.3	72.3		
Total (*1)	112.9	132.0	102.9	132.2	0.8	0.8	0.8	0.8	89.8	78.1	25.4	22.1
Additional GHG emission to generate 1kWh=3.6MJ electric power by means of power generation [g eq-CO_2/MJ-H_2]												
(Petroleum)	+81.6	+83.7	+81.6	+95.7	+113.7	+112.2	+104.6	+80.6	+97.3	+97.3	+97.3	+97.3
(LNG)	+65.8	+67.5	+65.8	+77.1	+91.7	+90.5	+84.3	+65.0	+78.5	+78.5	+78.5	+78.5
(LNG combined)	+53.9	+55.3	+53.9	+63.2	+75.1	+74.1	+69.1	+53.3	+64.3	+64.3	+64.3	+64.3
(Coal)	+102.3	+104.9	+102.2	+119.8	+142.3	+140.5	+131.0	+101.0	+121.9	+121.9	+121.9	+121.9
(Japan average) (*2)	+46.2	+47.4	+46.2	+54.2	+64.4	+63.5	+59.2	+45.7	+55.1	+55.1	+55.1	+55.1
(*1)+(*2)	159.2	179.5	149.1	186.4	65.1	64.3	60.0	46.4	144.9	133.2	80.5	77.3

Table 2.7.10 (A)　WTT energy efficiency of hydrogen production pathways (LHV)
(compressed hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsøe	PEC	NEDO	JHFC	case.1	case.2	case.3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.927	0.927	0.927	0.927					0.936	0.936	0.861	0.861
Hydrogen production / refining	0.674	0.573	0.740	0.555	0.868	0.873	0.901		0.650	0.743	0.650	0.743
Compression for distribution	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950
Domestic transport	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959	0.959
Compression / fueling	0.966	0.966	0.966	0.966	0.966	0.966	0.966	0.966	0.966	0.966	0.966	0.966
Total (*1)	0.549	0.467	0.604	0.452	0.764	0.768	0.792	0.880	0.536	0.612	0.492	0.563
Energy efficiency to generate 1kWh=3.6MJ electric power by means of power generation(LHV)												
(Petroleum)	0.358											
(LNG)	0.354											
(LNG combined)	0.422											
(Coal)	0.386											
(Japan average) (*2)	0.348											

Table 2.7.10 (B)　WTT energy efficiency of hydrogen production pathways (LHV)
(liquefied hydrogen transportation→compressed hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsøe	PEC	NEDO	JHFC	case.1	case.2	case.3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.927	0.927	0.927	0.927					0.936	0.936	0.861	0.861
Hydrogen production / refining	0.674	0.573	0.740	0.555	0.868	0.873	0.901		0.650	0.743	0.650	0.743
Liquefaction for distribution	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735
Domestic transport	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990
Gasification / compression / fueling	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995
Total (*1)	0.452	0.384	0.497	0.372	0.628	0.632	0.652	0.724	0.441	0.504	0.405	0.463
Energy efficiency to generate 1kWh=3.6MJ electric power by means of power generation(LHV)												
(Petroleum)	0.358											
(LNG)	0.354											
(LNG combined)	0.422											
(Coal)	0.386											
(Japan average) (*2)	0.348											

Table 2.7.10（C） WTT energy efficiency of hydrogen production pathways (LHV)
(liquefied hydrogen transportation→liquefied hydrogen fueling)

	Naphtha reforming				COG refining			Salt electrolysis	Raw natural gas reforming		CH4 fermentation / reforming	
	Topsøe	PEC	NEDO	JHFC	case1	case2	case3		(conventional)	(future)	(conventional)	(future)
Feedstock production	0.927	0.927	0.927	0.927					0.936	0.936	0.861	0.861
Hydrogen production / refining	0.674	0.573	0.740	0.555	0.868	0.873	0.901		0.650	0.743	0.650	0.743
Liquefaction for distribution	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735	0.735
Domestic transport	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990	0.990
Fueling as liquid	0.989	0.989	0.989	0.989	0.989	0.989	0.989	0.989	0.989	0.989	0.989	0.989
Total (*1)	0.449	0.382	0.494	0.370	0.625	0.628	0.648	0.720	0.438	0.501	0.403	0.460
Energy efficiency to generate 1kWh=3.6MJ electric power by means of power generation (LHV)												
(Petroleum)	0.358											
(LNG)	0.354											
(LNG combined)	0.422											
(Coal)	0.386											
(Japan average) (*2)	0.348											

3. Results and Conclusions

3.1 Well-to-Tank Analysis Results

(1) Energy Consumption [MJ/MJ-fuel (LHV)]

				Well-to-Tank		
				Best	Representative	Worst
Crude oil	Conventional diesel				0.078	
Crude oil	Low sulfur diesel				0.094	
Crude oil	Ultra low sulfur diesel				0.118	
Crude oil	Conventional gasoline				0.175	
Crude oil	Conventional gasoline	3% Ethanol blend gasoline		0.177		0.222
Crude oil	Conventional gasoline	10% Ethanol blend gasoline		0.182		0.338
Crude oil	Conventional gasoline	ETBE blend gasoline		0.177		0.218
Crude oil	Future gasoline				0.187	
Crude oil	Future gasoline	(on) Compressed Hydrogen			0.929	
Crude oil	Kerosene				0.066	
Crude oil	Kerosene	(on) Compressed Hydrogen			0.718	
Crude oil	Naphtha	(on) Compressed Hydrogen	(source:JHFC)		0.733	
Crude oil	Naphtha	(off) Compressed Hydrogen		0.612		1.455
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Compressed fueling)	1.360		2.203
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Fueling as liquid)	1.203		2.046
Crude oil	LPG from associated gas				0.120	
Crude oil	LPG from associated gas	(on) Compressed Hydrogen		0.763		0.833
Crude oil	LPG from petroleum refinery				0.151	
Crude oil	LPG from petroleum refinery	(on) Compressed Hydrogen		0.814		0.880
Crude oil	Crude / heavy fuel oil	Electricity			1.951	
Crude oil	Crude / heavy fuel oil	Electricity	(on) Compressed Hydrogen	4.512		6.375
Raw natural gas	LPG from raw natural gas				0.163	
Raw natural gas	LPG from raw natural gas	(on) Compressed Hydrogen		0.835		0.898
Raw natural gas	LNG				0.161	
Raw natural gas	LNG	City gas	(Fueling as CNG)		0.206	
Raw natural gas	LNG	City gas	(on) Compressed Hydrogen	0.693		0.724
Raw natural gas	LNG	Electricity (LNG thermal)			1.913	
Raw natural gas	LNG	Electricity (LNG thermal)	(on) Compressed Hydrogen	4.454		6.293
Raw natural gas	LNG	Electricity (LNG combined)			1.414	
Raw natural gas	LNG	Electricity (LNG combined)	(on) Compressed Hydrogen	3.691		5.215
Raw natural gas	(Pipeline transportation)	City gas	(Fueling as CNG)		0.120	
Raw natural gas	(Pipeline transportation)	City gas	(on) Compressed Hydrogen	0.585		0.599
Raw natural gas	(Pipeline transportation)	(off) Compressed Hydrogen		0.791		0.804
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Compressed fueling)	1.540		1.553
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Fueling as liquid)	1.383		1.396
Raw natural gas	Syngas	FT synthetic oil			0.553	
			<Estimation in this study>	<0.484>		<1.070>
Raw natural gas	Syngas	FT synthetic oil	(on) Compressed Hydrogen		1.579	
			<Estimation in this study>	<1.457>		<2.489>
Raw natural gas	Syngas	DME			0.468	
			<Estimation in this study>	<0.322>		<0.671>
Raw natural gas	Syngas	DME	(on) Compressed Hydrogen		1.112	
			<Estimation in this study>	<0.930>		<1.365>
Raw natural gas	Syngas	Methanol		0.524		0.589
			<Estimation in this study>	<0.777>		<1.205>
Raw natural gas	Syngas	Methanol	(on) Compressed Hydrogen	1.027		1.724
			<Estimation in this study>	<1.298>		<2.550>

(continued) Energy consumption

					Well-to-Tank		
					Best	Representative	Worst
Coal	Electricity					1.777	
Coal	Electricity	(on) Compressed Hydrogen			4.246		5.999
Coal	Syngas	FT synthetic oil			0.968		1.156
				<Estimation in this study>	<0.761>		
Coal	Syngas	FT synthetic oil	(on) Compressed Hydrogen		2.309		2.641
				<Estimation in this study>		<1.946>	
Coal	Syngas	DME		<Estimation in this study>		<0.759>	
Coal	Syngas	DME	(on) Compressed Hydrogen	<Estimation in this study>		<1.494>	
Coal	Syngas	Methanol		<Estimation in this study>		<0.821>	
Coal	Syngas	Methanol	(on) Compressed Hydrogen	<Estimation in this study>	<1.388>		<2.089>
Dry biomass (wood)	Syngas	FT synthetic oil			1.052		1.324
				<Estimation in this study>			<2.085>
Dry biomass (wood)	Syngas	FT synthetic oil	(on) Compressed Hydrogen		2.458		2.936
				<Estimation in this study>			<4.277>
Dry biomass (wood)	Syngas	DME				0.858	
				<Estimation in this study>		<0.749>	
Dry biomass (wood)	Syngas	DME	(on) Compressed Hydrogen			1.598	
				<Estimation in this study>		<1.462>	
Dry biomass (wood)	Syngas	Methanol			0.657		0.983
				<Estimation in this study>			<1.321>
Dry biomass (wood)	Syngas	Methanol	(on) Compressed Hydrogen		1.170		2.252
				<Estimation in this study>	<1.882>		<2.706>
Dry biomass (wood)	(Direct combustion)	Electricity				5.656	
Dry biomass (wood)	(Direct combustion)	Electricity	(on) Compressed Hydrogen		11.726		16.567
Dry biomass (wood)	(Gasification IGCC)	Electricity				0.850	
Dry biomass (wood)	(Gasification IGCC)	Electricity	(on) Compressed Hydrogen		4.365		6.167
Rapeseed	BDF				0.420		0.616
Palm	BDF				0.220		0.289
Waste food oil	BDF					0.061	
Sugarcane	Ethanol				0.230		1.060
Sugarcane	Ethanol	ETBE			0.209		0.476
Corn	Ethanol				0.946		1.055
Corn	Ethanol	ETBE			0.407		0.474
Plantation wood	Ethanol				1.527		2.673
Plantation wood	Ethanol	ETBE			0.637		1.030
Waste wood	Ethanol					1.690	
Waste wood	Ethanol	ETBE				0.682	
Wet biomass	CH_4	(Fueling as CNG)			0.814		0.823
Wet biomass	CH_4	(off) Compressed Hydrogen			1.449		1.561
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Compressed fueling)		2.197		2.310
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Fueling as liquid)		2.040		2.153
Wet biomass	CH_4	Electricity				1.032	
Wet biomass	CH_4	Electricity	(on) Compressed Hydrogen		3.797		5.365
Power grid (Japan average)						1.877	
Power grid (Japan average)	(on) Compressed Hydrogen				4.407		6.226
(Salt electrolysis)	(off) Compressed Hydrogen					0.487	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Compressed fueling)				1.235	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Fueling as liquid)				1.078	
(COG)	(off) Compressed Hydrogen				0.804		0.924
(COG)	(off) Liquefied Hydrogen	(Compressed fueling)			1.552		1.672
(COG)	(off) Liquefied Hydrogen	(Fueling as liquid)			1.395		1.515

(2) GHG Emissions [g-eq CO_2/MJ-fuel (LHV)]

				Well-to-Tank		
				Best	Representative	Worst
Crude oil	Conventional diesel				5.45	
Crude oil	Low sulfur diesel				6.43	
Crude oil	Ultra low sulfur diesel				7.88	
Crude oil	Conventional gasoline				11.42	
Crude oil	Conventional gasoline	3% Ethanol blend gasoline		10.17		13.18
Crude oil	Conventional gasoline	10% Ethanol blend gasoline		7.14		17.44
Crude oil	Conventional gasoline	ETBE blend gasoline		10.34		13.05
Crude oil	Future gasoline				12.19	
Crude oil	Future gasoline	(on) Compressed Hydrogen			176.68	
Crude oil	Kerosene				4.72	
Crude oil	Kerosene	(on) Compressed Hydrogen			159.87	
Crude oil	Naphtha	(on) Compressed Hydrogen	(source:JHFC)		163.43	
Crude oil	Naphtha	(off) Compressed Hydrogen		124.86		162.19
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Compressed fueling)	155.78		193.11
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Fueling as liquid)	149.07		186.40
Crude oil	LPG from associated gas				7.76	
Crude oil	LPG from associated gas	(on) Compressed Hydrogen		122.39		141.45
Crude oil	LPG from petroleum refinery				9.93	
Crude oil	LPG from petroleum refinery	(on) Compressed Hydrogen		125.64		145.01
Crude oil	Crude / heavy fuel oil	Electricity			217.66	
Crude oil	Crude / heavy fuel oil	Electricity	(on) Compressed Hydrogen	332.83		470.22
Raw natural gas	LPG from raw natural gas				12.32	
Raw natural gas	LPG from raw natural gas	(on) Compressed Hydrogen		129.22		148.93
Raw natural gas	LNG				12.68	
Raw natural gas	LNG	City gas	(Fueling as CNG)		13.52	
Raw natural gas	LNG	City gas	(on) Compressed Hydrogen	108.13		121.34
Raw natural gas	LNG	Electricity (LNG thermal)			175.51	
Raw natural gas	LNG	Electricity (LNG thermal)	(on) Compressed Hydrogen	268.37		379.16
Raw natural gas	LNG	Electricity (LNG combined)			143.75	
Raw natural gas	LNG	Electricity (LNG combined)	(on) Compressed Hydrogen	219.81		310.55
Raw natural gas	(Pipeline transportation)	City gas	(Fueling as CNG)		6.30	
Raw natural gas	(Pipeline transportation)	City gas	(on) Compressed Hydrogen	98.98		110.80
Raw natural gas	(Pipeline transportation)	(off) Compressed Hydrogen		108.99		120.71
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Compressed fueling)	139.92		151.63
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Fueling as liquid)	133.20		144.92
Raw natural gas	Syngas	FT synthetic oil			22.99	
			< Estimation in this study >	<17.82>		<52.63>
Raw natural gas	Syngas	FT synthetic oil	(on) Compressed Hydrogen		192.27	
			< Estimation in this study >	<183.17>		<244.48>
Raw natural gas	Syngas	DME			17.14	
			< Estimation in this study >	<12.90>		<33.66>
Raw natural gas	Syngas	DME	(on) Compressed Hydrogen		133.06	
			< Estimation in this study >	<127.78>		<153.65>
Raw natural gas	Syngas	Methanol		22.93		26.77
			< Estimation in this study >	<37.94>		<63.40>
Raw natural gas	Syngas	Methanol	(on) Compressed Hydrogen	123.84		168.32
			< Estimation in this study >	<139.94>		<217.40>

(continued) GHG emissions

					Well-to-Tank		
					Best	Representative	Worst
Coal	Electricity					272.60	
Coal	Electricity	(on) Compressed Hydrogen			416.82		538.90
Coal	Syngas	FT synthetic oil			66.78		68.14
				< Estimation in this study >	<59.13>		
Coal	Syngas	FT synthetic oil	(on) Compressed Hydrogen		269.41		271.79
				< Estimation in this study >		<255.92>	
Coal	Syngas	DME		< Estimation in this study >		<63.31>	
Coal	Syngas	DME	(on) Compressed Hydrogen	< Estimation in this study >		<230.43>	
Coal	Syngas	Methanol		< Estimation in this study >		<65.43>	
Coal	Syngas	Methanol	(on) Compressed Hydrogen	< Estimation in this study >	<248.41>		<318.84>
Dry biomass (wood)	Syngas	FT synthetic oil			△64.40		△63.73
				< Estimation in this study >			<△61.85>
Dry biomass (wood)	Syngas	FT synthetic oil	(on) Compressed Hydrogen		41.39		42.97
				< Estimation in this study >			<47.40>
Dry biomass (wood)	Syngas	DME				△59.11	
				< Estimation in this study >		<△59.38>	
Dry biomass (wood)	Syngas	DME	(on) Compressed Hydrogen			39.95	
				< Estimation in this study >		<39.50>	
Dry biomass (wood)	Syngas	Methanol			△60.40		△59.60
				< Estimation in this study >			<△58.76>
Dry biomass (wood)	Syngas	Methanol	(on) Compressed Hydrogen		35.95		54.77
				< Estimation in this study >	<38.30>		<56.27>
Dry biomass (wood)	(Direct combustion)	Electricity				45.34	
Dry biomass (wood)	(Direct combustion)	Electricity	(on) Compressed Hydrogen		69.45		98.12
Dry biomass (wood)	(Gasification IGCC)	Electricity				7.97	
Dry biomass (wood)	(Gasification IGCC)	Electricity	(on) Compressed Hydrogen		12.21		17.26
Rapeseed	BDF				△50.95		△39.10
Palm	BDF				△56.84		△52.95
Waste food oil	BDF					△73.28	
Sugarcane	Ethanol				△54.31		△51.89
Sugarcane	Ethanol	ETBE			△10.26		△9.43
Corn	Ethanol				△2.31		21.92
Corn	Ethanol	ETBE			7.60		15.92
Plantation wood	Ethanol				27.36		103.80
Plantation wood	Ethanol	ETBE			17.78		44.04
Waste wood	Ethanol					23.95	
Waste wood	Ethanol	ETBE				16.61	
Wet biomass	CH_4	(Fueling as CNG)			△32.93		△30.73
Wet biomass	CH_4	(off) Compressed Hydrogen			53.05		56.29
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Compressed fueling)		83.97		87.21
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Fueling as liquid)		77.26		80.50
Wet biomass	CH_4	Electricity				41.17	
Wet biomass	CH_4	Electricity	(on) Compressed Hydrogen		63.07		89.10
Power grid (Japan average)						123.06	
Power grid (Japan average)	(on) Compressed Hydrogen				188.49		266.30
(Salt electrolysis)	(off) Compressed Hydrogen					22.23	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Compressed fueling)				53.15	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Fueling as liquid)				46.44	
(COG)	(off) Compressed Hydrogen				35.79		40.93
(COG)	(off) Liquefied Hydrogen	(Compressed fueling)			66.71		71.85
(COG)	(off) Liquefied Hydrogen	(Fueling as liquid)			60.00		65.14

(3) Energy efficiency (LHV)

				Well-to-Tank		
				Best	Representative	Worst
Crude oil	Conventional diesel				0.916	
Crude oil	Low sulfur diesel				0.902	
Crude oil	Ultra low sulfur diesel				0.883	
Crude oil	Conventional gasoline				0.839	
Crude oil	Conventional gasoline	3% Ethanol blend gasoline		0.838		0.822
Crude oil	Conventional gasoline	10% Ethanol blend gasoline		0.836		0.782
Crude oil	Conventional gasoline	ETBE blend gasoline		0.833		0.803
Crude oil	Future gasoline				0.830	
Crude oil	Future gasoline	(on) Compressed Hydrogen			0.431	
Crude oil	Kerosene				0.924	
Crude oil	Kerosene	(on) Compressed Hydrogen			0.486	
Crude oil	Naphtha	(on) Compressed Hydrogen	(source: JHFC)		0.452	
Crude oil	Naphtha	(off) Compressed Hydrogen		0.604		0.452
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Compressed fueling)	0.497		0.372
Crude oil	Naphtha	(off) Liquefied Hydrogen	(Fueling as liquid)	0.494		0.370
Crude oil	LPG from associated gas				0.889	
Crude oil	LPG from associated gas	(on) Compressed Hydrogen		0.565		0.486
Crude oil	LPG from petroleum refinery				0.916	
Crude oil	LPG from petroleum refinery	(on) Compressed Hydrogen		0.582		0.501
Crude oil	Crude / heavy fuel oil	Electricity			0.358	
Crude oil	Crude / heavy fuel oil	Electricity	(on) Compressed Hydrogen	0.241		0.168
Raw natural gas	LPG from raw natural gas				0.853	
Raw natural gas	LPG from raw natural gas	(on) Compressed Hydrogen		0.541		0.467
Raw natural gas	LNG				0.858	
Raw natural gas	LNG	City gas	(Fueling as CNG)		0.848	
Raw natural gas	LNG	City gas	(on) Compressed Hydrogen	0.622		0.545
Raw natural gas	LNG	Electricity (LNG thermal)			0.354	
Raw natural gas	LNG	Electricity (LNG thermal)	(on) Compressed Hydrogen	0.239		0.166
Raw natural gas	LNG	Electricity (LNG combined)			0.422	
Raw natural gas	LNG	Electricity (LNG combined)	(on) Compressed Hydrogen	0.285		0.198
Raw natural gas	(Pipeline transportation)	City gas	(Fueling as CNG)		0.918	
Raw natural gas	(Pipeline transportation)	City gas	(on) Compressed Hydrogen	0.674		0.590
Raw natural gas	(Pipeline transportation)	(off) Compressed Hydrogen		0.612		0.536
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Compressed fueling)	0.504		0.441
Raw natural gas	(Pipeline transportation)	(off) Liquefied Hydrogen	(Fueling as liquid)	0.501		0.433
Raw natural gas	Syngas	FT synthetic oil			0.638	
			<Estimation in this study>	<0.668>		<0.477>
Raw natural gas	Syngas	FT synthetic oil	(on) Compressed Hydrogen		0.336	
			<Estimation in this study>	<0.352>		<0.251>
Raw natural gas	Syngas	DME			0.671	
			<Estimation in this study>	<0.748>		<0.587>
Raw natural gas	Syngas	DME	(on) Compressed Hydrogen		0.447	
			<Estimation in this study>	<0.499>		<0.391>
Raw natural gas	Syngas	Methanol		0.640		0.613
			<Estimation in this study>	<0.545>		<0.435>
Raw natural gas	Syngas	Methanol	(on) Compressed Hydrogen	0.500		0.379
			<Estimation in this study>	<0.425>		<0.269>

(continued) Energy efficiency

					Well-to-Tank		
					Best	Representative	Worst
Coal	Electricity					0.386	
Coal	Electricity	(on) Compressed Hydrogen			0.260		0.181
Coal	Syngas	FT synthetic oil			0.508		0.463
				< Estimation in this study >	<0.568>		
Coal	Syngas	FT synthetic oil	(on) Compressed Hydrogen		0.267		0.244
				< Estimation in this study >		<0.299>	
Coal	Syngas	DME		< Estimation in this study >		<0.565>	
Coal	Syngas	DME	(on) Compressed Hydrogen	< Estimation in this study >		<0.377>	
Coal	Syngas	Methanol		< Estimation in this study >		<0.542>	
Coal	Syngas	Methanol	(on) Compressed Hydrogen	< Estimation in this study >	<0.423>		<0.335>
Dry biomass (wood)	Syngas	FT synthetic oil			0.489		0.431
				< Estimation in this study >			<0.324>
Dry biomass (wood)	Syngas	FT synthetic oil	(on) Compressed Hydrogen		0.257		0.227
				< Estimation in this study >			<0.171>
Dry biomass (wood)	Syngas	DME				0.536	
				< Estimation in this study >		<0.570>	
Dry biomass (wood)	Syngas	DME	(on) Compressed Hydrogen			0.357	
				< Estimation in this study >		<0.380>	
Dry biomass (wood)	Syngas	Methanol			0.597		0.496
				< Estimation in this study >			<0.422>
Dry biomass (wood)	Syngas	Methanol	(on) Compressed Hydrogen		0.466		0.307
				< Estimation in this study >	<0.329>		<0.261>
Dry biomass (wood)	(Direct combustion)	Electricity				0.094	
Dry biomass (wood)	(Direct combustion)	Electricity	(on) Compressed Hydrogen		0.063		0.044
Dry biomass (wood)	(Gasification IGCC)	Electricity				0.329	
Dry biomass (wood)	(Gasification IGCC)	Electricity	(on) Compressed Hydrogen		0.222		0.154
Rapeseed	BDF				0.891		0.734
Palm	BDF				0.969		0.916
Waste food oil	BDF					0.988	
Sugarcane	Ethanol				0.815		0.466
Sugarcane	Ethanol	ETBE			0.739		0.423
Corn	Ethanol				0.554		0.552
Corn	Ethanol	ETBE			0.502		0.501
Plantation wood	Ethanol				0.392		0.271
Plantation wood	Ethanol	ETBE			0.356		0.246
Waste wood	Ethanol					0.374	
Waste wood	Ethanol	ETBE				0.339	
Wet biomass	CH_4	(Fueling as CNG)			0.804		0.780
Wet biomass	CH_4	(off) Compressed Hydrogen			0.563		0.492
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Compressed fueling)		0.463		0.405
Wet biomass	CH_4	(off) Liquefied Hydrogen	(Fueling as liquid)		0.460		0.403
Wet biomass	CH_4	Electricity				0.183	
Wet biomass	CH_4	Electricity	(on) Compressed Hydrogen		0.123		0.086
Power grid (Japan average)						0.348	
Power grid (Japan average)	(on) Compressed Hydrogen				0.235		0.163
(Salt electrolysis)	(off) Compressed Hydrogen					0.880	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Compressed fueling)				0.724	
(Salt electrolysis)	(off) Liquefied Hydrogen	(Fueling as liquid)				0.720	
(COG)	(off) Compressed Hydrogen				0.792		0.764
(COG)	(off) Liquefied Hydrogen	(Compressed fueling)			0.652		0.628
(COG)	(off) Liquefied Hydrogen	(Fueling as liquid)			0.648		0.625

3.2 Case Study: Tank-to-Wheel and Well-to-Wheel GHG Emissions

3.2.1 Assumptions about Tank-to-Wheel analysis

Tank-to-Wheel data derived from previous research studies conducted by TMC was used. The outline of this data is as follows.

(1) Vehicle Specification

Sedan type passenger vehicle, weight: 1,250 kg, displacement: 2,000cc, four-cylinder gasoline engine, automatic transmission.

(2) Running Conditions

The great effect that running conditions will have on Well-to-Wheel calculation results is acknowledged. Although various running conditions should be considered for evaluation purposes, as this study is classed as a reference case study, the running pattern used in Japan for fuel consumption measurements, the "10/15 mode run", has been used.

(3) Powertrains

The internal combustion engine, hybrid engine and fuel cell were selected as typical powertrains, and combined with the relevant fuels indicated in "3.1 Well-to-Tank Calculation Results for Evaluated Fuels".

The fuel consumption ratios and exhaust gas levels (emissions targets) for each powertrain in relation to the base vehicle is shown in Table 3.2.1.

Table 3.2.1 Mileage and emission target of representative powertrains covered in this study

Representative powertrain	Mileage[*1] (ratio of base value)	Emission target
Gasoline vehicle	1.00 (base value)	Lower than the new long-term regulation value for gasoline
Gasoline hybrid vehicle	2.31	↑
LPG vehicle	1.00	↑
Natural gas vehicle	1.00	↑
Diesel vehicle	1.25	Lower than the new short-term regulation value for diesel (complying with the acts for NOx and PM)
Diesel hybrid vehicle	2.44[*2]	↑
Fuel cell vehicle	3.75[*3]	0 (equivalent to the U.S. Tier-2 Bin 1)

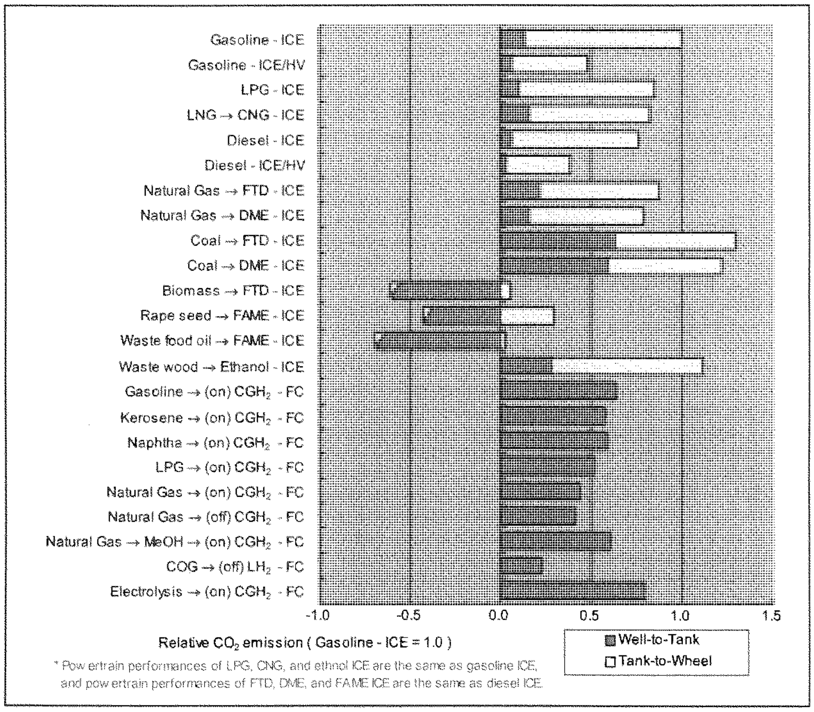
Note [*1]: Mileage per litre in which each fuel is converted into gasoline equivalence based on heating value. Represented in relative values to that of gasoline vehicle.

[*2] : Estimation from public documents [*3] : Future target

Regarding power performance, powertrain specifications were adjusted to generally match the base vehicle, taking the system weight and performance of each powertrain into consideration.

3.2.2 Well-to-Wheel GHG emissions under fixed conditions of driving sedan type vehicles

Well-to-Wheel GHG emissions under the condition described in 3.2.1 are shown in Figure 3.2.1



* Powertrain performances of LPG, CNG, and ethnol ICE are the same as gasoline ICE, and powertrain performances of FTD, DME, and FAME ICE are the same as diesel ICE.

Figure 3.2.1 An example of calculation of Well-to-Wheel GHG emissions

As with prior studies, at the comparatively slow running speed of the "10/15 mode run", the superiority of the hybrid vehicle (gasoline, diesel) in relation to GHG emissions is significant.

For synthetic fuels such as Fischer-Tropsch diesel oil and Dimethyl ether (DME), and hydrogen, large variations in Well-to-Tank GHG emissions were apparent depending on the primary energy used as feedstock, and it is clear that an important aspect of future considerations will be the production of fuels through low GHG emission pathways. In addition, fuels derived from biomass resources have comparatively low GHG emission values, and future utilization is anticipated.

The calculation results for Well-to-Wheel GHG emissions indicated in this report represent a case study under a given set of conditions, and cannot be applied to discussion concerning the superiority of particular future automotive fuels and powertrains. Further evaluation from a comprehensive perspective encompassing the price of each vehicle and fuels (economical efficiency), supply, ease of use, and so on, is necessary.

3.3 Considerations and Future Tasks

3.3.1 Considerations about Well-to-Tank analysis

The calculations of this study mainly concern Well-to-Tank (=consideration of the fuel from extraction of primary energy to vehicle fuel tank) energy consumption, greenhouse gas (GHG) emissions and energy efficiency of current and near future automotive fuels in Japan. No fixed timeframe was set for the data collected, with efforts focusing on understanding and organizing existing data. Moreover, where data used in calculation has a broad range, the range is indicated through minimum to maximum values.

The fuel production pathways considered were; 21 petroleum based fuels, 20 natural gas based fuels, 8 coal based fuels, 19 biomass resource related fuels (3 bio-diesel fuels, 10 dry biomass based fuels, 6 wet biomass based fuels), power grid mix (Japan average) and hydrogen production through electrolysis, 6 byproduct hydrogen, totaling 76 pathways. The calculation results are as shown in "3.1 Well-to-Tank Analysis Results".

(1) Petroleum Based Fuel Production Pathways → 2.1

For petroleum based fuel production pathways, focusing on fuels for current mainstream internal combustion engines, diesel and gasoline, this study considered low-sulfur diesel, ultra low sulfur diesel and future (sulfur-free) gasoline derived through ultra deep hydrodesulfurization, and biomass based ethanol and ETBE blend gasoline (hydrogen from reformed petroleum products will be mentioned later). Energy efficiency related to the production of these fuels is high at 0.83-0.92.

There are two main uncertain factors in the calculation of data related to petroleum based fuel production pathways. The first is the effect of sulfur content in crude. The effects of differences in producing region are greater than the effects of technological factors related to desulfurization. As the vast majority of crude oil currently consumed in Japan is imported from the Middle East, data calculated from statistical values, such as in this study, will tend to reflect the properties of Middle East crude. The sulfur content of Middle East crude is just under 2 %, with high aromatic content. On the other hand, the import of low sulfur content Russian and African crude has recently increased. African crude is a low-sulfur crude with properties similar to North Sea crude. Although North Sea crude is a top quality crude with less than 0.1% sulfur content, it is rarely imported into Japan. In addition, Russian crude is currently drawing the most attention, and this too has comparatively low sulfur content. Should these crude oils replace 20-30 % of the imported Middle East crude, the data given here may change dramatically (petroleum refining process including desulfurization). Such significant effects of sulfur content at source are a characteristic of petroleum based fuels (effects of differences in producing region).

The second is the effect of petroleum resources known as "unconventional resources" (= low-sulfur petroleum feedstock for refining produced through the processing of such as oil sands. Synthetic crude), which are not included in current statistics. The use of this feedstock is increasing rapidly in the U.S. In addition, statistics for Canada show that synthetic crude exceeded natural crude this year. Regarding price, crude is comparatively expensive at 40-50 dollars per barrel, whereas synthetic crude is less than 20 dollars per barrel. Moreover, as resource stocks are practically inexhaustible, depending on price, the importance of synthetic crude may increase in the future. However, on the other hand, problems do exist in that increase in synthetic crude usage will be accompanied by an increase in CO_2 emissions.

It is also necessary to consider the petroleum refining process as a factor specific to Japan. The characteristic of refining in Japan is that unlike the U.S., which uses thermal cracking to produce maximum gasoline, Japan uses mild cracking, applying large amounts of hydrogen to yield approximately 20% kerosene (there is almost no kerosene usage overseas). Although there are thermal cracking techniques using catalysts that can be applied to increase gasoline yield, as in the U.S., these will result in decreased energy efficiency. In reality, in comparison to the U.S., overall efficiency in Japan is said to be 2-4 % better. In addition, an uncertain factor in the future of the petroleum refining process in Japan is the positioning of C-heavy fuel oil. Until now, industrial use of C-heavy fuel oil centered on power companies, however this usage may be discontinued. Should current consumption conditions progress as they are, in the future, C-heavy fuel oil may be broken down into gasoline or diesel, resulting in a decrease in process efficiency.

(2) Natural Gas Based Fuel Production Pathways → 2.2

For natural gas based fuel production pathways, this study considered liquid natural gas (LNG), which physically enhances energy density, and compressed natural gas (CNG) derived from compressed city gas (hydrogen from reformed natural gas will be mentioned later). Regarding supply routes, other than LNG, a case study of pipeline transportation from Sakhalin was also undertaken.

Okamura *et al.* [2004] referenced in this study, gathers the latest information regarding the LNG Middle East project (Qatar, Oman) implemented from the perspective of diversification of LNG procurement, and analyzes the effects on GHG emissions over the LNG lifecycle (LNG used in Japan) with the addition of the Middle East LNG project. Okamura *et al.* [2004] reported that although the shipping distance doubled for the Middle East, representing a possibility of GHG emissions increasing for the overall lifecycle, as the CO_2 content of feedstock from the Middle East LNG project was lower, overall GHG emissions were also lower. Feedstock from Arun, Indonesia contains the most CO_2, however this is nearing depletion. Although Japan will cover the volume previously procured from Arun with imports from the Middle East, GHG emissions for the overall lifecycle will not increase. CO_2 content of feedstock from Sakhalin is also though to be low.

In addition, under the preconditions set in this study, the results showed that GHG emissions would be lower in the case of pipeline transportation from Sakhalin. The FRI-ERC [2000] report also states, "From the environmental perspective, if the shipping distance is less than 16,000 km, pipeline transportation is better than LNG, and for shorter distances of 2,000-3,000 km, pipeline transportation is significantly better". There are currently many difficult problems of investment risk, politics and so on concerning pipeline transportation. When taken into consideration as a measure against global warming in the future, should the pipeline transportation of natural gas from neighboring countries become a possibility, it will be an attractive prospect worthy of implementation.

(3) Fuel Production Pathways from Biomass Resources → 2.3

For fuel production pathways from biomass resources, this study considered BDF from oil crops and waste food oil, ethanol and ETBE produced from cellulosic materials such as sugar/starch and wood (used as a blend with gasoline), and CH_4 fermentation (synthetic fuels from biomass will be mentioned later). As the conversion technology for biomass resources is still in the research stages, how the future is viewed from the current stages of research will be important.

In addition, considerations must be made concerning a variety of restrictions regarding introduction and dissemination. For example, the introduction and dissemination of BDF may involve restrictions in cost and production volume.

At present, with BDF usage in Japan, tax equivalent to tax on diesel is imposed when the BDF is blended with diesel (diesel excise duty). Assuming usage as a blend with diesel, the desirable Well-to-Tank BDF production cost, taking diesel excise duty into account, would be about 30 yen. In addition, according to data provided in reference materials, assuming daily production of about 200-300 L-BDF, in order to recover the cost of the esterification device within the serviceable life of the reclaimed oil production device (8 years), about 10-20 yen per liter BDF needs to be gained. In other words, large-scale production to exploit scale merit, and BDF dissemination on the premise of single BDF usage (not blended with diesel) will be necessary. Furthermore, for BDF production from agricultural products, as labor costs are a major burden in areas that cannot be mechanized, there are generally many cases of increased cost. Therefore, the maintenance of cost competitiveness through the use of waste cooking oils, which can be recovered free of charge (or inverse onerous contracts) is important.

On the other hand, on the production side, due to competition with food crops, the use of abandoned cropland and unused land is assumed for the cultivation of rapeseed. Currently, in Japan, although there are over 210,000 ha of abandoned cropland consisting of paddies, fields and orchards, approximately three quarters of this land is in plots of less than 5 ha. As a plot of land less than 5 ha can only be expected to produce about 3.7 kL-BDF per year, for a 1,500 kL/year class plant such as the one under consideration by Kyoto City, it will be necessary to cultivate rapeseed in 400 plots. In addition, as there will be great differences in the distribution of large-scale plots of unused land (greater than 30 ha) depending on region, from the perspective of nationwide dissemination, the utilization of unused plots is unrealistic. Consequently, the establishment of a scheme whereby as much waste cooking oil as possible is collected from homes in a metropolitan area, and the waste cooking oil generated by businesses is collected on a stable basis, is desired.

When considering these restrictions, the stable dissemination of BDF in Japan will most likely stem from BDF derived from imported palm oil, and this accompanied by the utilization of waste cooking oil is considered realistic. However, should political backing favor rapeseed (oil crop cultivation including rapeseed), dissemination may progress with the production of low-cost BDF through mechanized agricultural work. In addition, when the premise is of importation, attention must be paid to important points such as demand/supply balance with other countries and measures against country risk.

Following on, for the introduction and dissemination of ethanol, food demand and supply trends must be kept in mind when using saccharides (e.g. corn, sugarcane), and farming and waste treatment trends must be kept in mind when using cellulosic resources (e.g. wood, waste wood).

Although ethanol production using corn and other farinaceous crops as feedstock is currently being promoted, mainly in the U.S. and Europe, crops such as corn are also important food crops, and variations in climate can cause sharp increases in trading prices. This will also greatly affect the ethanol production cost. In fact, the effect of climate risk in relation to corn ethanol is said to be greater than that of country risk on crude prices.

The relationship with sugar production is thought to have great influence regarding sugarcane. This trend is particularly noticeable in Brazil where cane expression businesses directly produce ethanol. In addition, Brazil produces approximately 30 % of the worlds sugar and accounts for approximately 40 % of exports. This suggests the possibility that, if growers in Brazil focus on sugar production due to variations in international sugar prices, ethanol demand and supply may become restricted.

The ethanol conversion of cellulosic biomass is currently in the stages of technological development, and it is thought that the introduction and dissemination of this technology will be promoted in countries such as Japan that have difficulty in securing saccharide resources. Other than woody biomass, viable cellulosic resources include rice straw, wheat straw, wastepaper and so on. Although in many cases in the U.S., the target is wheat-straw, the same cannot be expected in Japan as paddy fields are not necessarily large-scale and are also dispersed, therefore the focus is expected to be on the utilization of construction generated wood (waste wood).

When considering these restrictions, implementation will progress for the time being with imported alcohol as the main source, with a changeover to cellulosic ethanol production in line with technological advancements. As it is difficult to imagine the import of corn from the U.S., this is not a realistic option for Japan.

(4) Synthetic Fuel Production Pathways → 2.4

For synthetic fuel production pathways, considerations were made for 3 types of primary energy (gas) that would be the source (natural gas, gas from coal cracking, biomass gasification gas) and 3 types of synthetic fuel (FT synthetic oil, DME, methanol), so calculations energy efficiency and so on were made regarding the 9 (= 3 * 3) production pathways these represent.

In this study, as existing studies were not available for all nine pathways, other than using prior research for reference in calculations of energy efficiency and so on, conditions were set for a given process, and estimates of energy efficiency were made under those conditions. Although the estimate results generally matched the results calculated using prior researches for reference, significant discrepancies were shown for some pathways. This is because the estimates for gas composition assumed total volume to be CH_4, however the reality was that some non-CH_4 constituents were included, and synthetic fuel is thought to be produced through a reforming method suitable for that composition (it is thought that for the production of all synthetic fuels from natural gas, the optimum reforming process is determined automatically according to the required H_2/CO ratio). In other words, in an industrialized facility, the optimum process has been adopted, and based on this the values given in reference literature are considered to be the good efficiency values. However, for the estimate results of this study, all four reforming process types were considered and trial calculations conducted for each with best and worst values given, resulting in the aforementioned discrepancies. In addition, since in some cases there was insufficient information for the conditions set for trial calculations, further information related to the process should be considered with a view to improving accuracy, and the trial calculation model should be studied.

Furthermore, unlike petroleum products and natural gas, which are already in industrial use, usage of synthetic fuels as automotive fuel does not have an established industrial usage base, and in relation to all these pathways, considerations into product quality as an automotive fuel have not been made. Regarding the production pathways of synthetic fuels as automotive fuels, improving the accuracy of calculation results derived from such considerations remains as a future objective.

(5) Liquefied Petroleum Gas Production Pathways → 2.5

For LPG production pathways, the LPG production methods used in Japan – collection of LPG through separation and processing of gas associated with crude oil (LPG from associated gas), collection of LPG through separation and processing of gas extracted from gas fields (LPG from raw natural gas), and collection of LPG as a byproduct from refineries and petrochemical plants (LPG from petroleum refining), were considered.

As an automotive fuel, LPG is supplied to established LPG vehicles already in use such as taxis, commercial vehicles and trucks. The propane/butane constituent ratio (weight) of LPG used in motor vehicles is about 20:80 in summer and about 30:70 in winter. In prior studies referenced in this study, information regarding the quality of these ratios is unclear. Regarding the production pathways of LPG as an automotive fuel, improving the accuracy of calculation results derived from such considerations remains as a future objective.

(6) Electricity (Electric Power Generation Pathways) → 2. 6

For electrical power (power generation pathways), petroleum fired thermal, LNG and LNG combined cycle, coal fired thermal, nuclear and biomass power generation, and the electricity mix from the average power generation structure of Japan, were considered. Electric power is used to recharge electric vehicles and for hydrogen production through water electrolysis.

Attention must be paid to data used in the calculation of CO_2 emissions and energy efficiency associated with electricity usage, as changes in this data will occur depending on perspective, such as the use of a single fossil fuel or the use of energy to power vehicles. From the perspective of how a fossil fuel should be used, it is appropriate to investigate how CO_2 emissions and energy efficiency is affected through the various pathways from one fossil fuel. On the other hand, from the perspective of what should be used to power motor vehicles, it is appropriate to consider energy use as 1 kWh = 3.6 MJ, regardless of the primary energy.

Regarding electricity generation mix (Japan average), when using the calculation results, attention must be paid to the fact that CO_2 emissions associated with electricity use are thinned out. If electricity is to provide energy for transportation, new power plants will be required, and considerations must be made into what will be used in the new power plants to supply the energy to meet the new demand.

In addition, for biomass power generation (direct combustion, steam gas turbine power generation, gasification gas turbine power generation, CH_4 fermentation gas engine power generation), differences in the composition of the input and processes (including reaction conditions) greatly affect the results. The calculation results of biomass power generation in this study are all derived from information relevant to a specific site, and may be uncertain and varied in comparison to the calculation results for all thermal and nuclear power generation. Improvement of accuracy here also remains as a future objective.

(7) Hydrogen Production Pathways → 2. 7

For hydrogen production pathways, following transportation to hydrogen stations in the form of petroleum products, city gas, pure water and so on, considerations were made for cases where hydrogen is produced through hydrogen production devices (on-site), and cases where hydrogen is produced at large-scale facilities such as a central plant and shipped out in the form of compressed or liquefied hydrogen (off-site).

Hydrogen for use as fuel for FCVs does not exist as elementary substance in a natural state, and as shown in pathways considered in this study, conventional energy sources must be relied upon for production (although GHG emissions associated with hydrogen production are practically zero when renewable energy is used, at present, such renewable energy is not in general use).

The majority of hydrogen production pathways considered in this study have not as yet reached levels suitable for practical application. In other words, much of the data used for calculation in this study is based on ideals, and the task remains as to how estimates should be made concerning deviation between these results and data that will become available following industrialization.

In addition, this study considers byproduct hydrogen as a secondary product. However, for ironworks and caustic soda plants where byproduct hydrogen is used effectively, it will be necessary to consider alternative fuels to supplement energy deficiencies incurred through the use of hydrogen as fuel for FCVs. In such cases (where utilization is sufficient), by the calculation results of this study, usage for FCVs will not be effective.
At this point, based on the calculation results of this study, hydrogen cannot be said to be particularly superior to conventional fuels. However, the attraction of hydrogen is in <i> no GHG emissions during use and <ii> can be extracted from various resources (diversity of feedstock). In addition, unlike CO_2 emissions from existing systems such as gasoline vehicles, CO_2 emissions from the hydrogen production process are generated in specific locations and may be recovered and sequestered. Depending on trends in the recovery and sequestration of CO_2, huge reductions can be expected in GHG emissions from hydrogen production pathways. Furthermore, depending greatly on regional characteristics, further improvements can be made on the energy efficiency of hydrogen such as through the use of waste heat from reforming for cogeneration. Taking all these points into consideration, it will be necessary to seek appropriate hydrogen production pathways.

3.3.2 Future Tasks

The credibility and applicability of calculations in this study depends greatly on calculation preconditions such as implemented load distribution methods and quality of data. In reality, some fuels such as petroleum products, city gas, LPG and electricity are already in industrial use, while biomass resources, synthetic fuels, hydrogen and so on are still in the early stages of technological development. In addition, even where calculation results of this study are based on actual values, as there is a high degree of uncertainty concerning matters such as future technological innovation, market size, new laws and regulations, many problems exist concerning the simple comparison of these fuels. Furthermore, regarding load distribution between main products and co-products/byproducts, although this study has been conducted under the premise that, in principle, byproducts will be disposed of, the usage of certain byproducts has been considered in existing studies although the possibility of realizing this usage is unclear (load distribution considerations). For these reasons, the calculation results of this study are not unlike preliminary approximations, and in order to contribute further to the initial objectives, the consistency of preconditions and the accuracy of data used in calculations must be improved, and the credibility of the results must be enhanced.

The emphasis of this study is on Well-to-Tank analysis. In future, these results will be combined with various Tank-to-Wheel analysis results and basic data, and various further analyses will be scheduled in relation to overall efficiency from extraction of primary energy to actual vehicle fuel consumption "Well-to-Wheel" (see Figure 3.2.1). At such a time, it may also become necessary to modify or adjust the calculation results of this study in order to comply with analysis preconditions.

Well-to-Wheel analysis results will be an important factor in the selection of future technologies and fuels. However, technologies and fuels that will be implemented in the future will not be determined by this factor alone. This is because a variety of other factors such as cost, infrastructure, completeness of the technology, supply potential and usability will also be taken into consideration. In future, it will be necessary to seek out optimum vehicle/fuel combinations according to the energy circumstances, available infrastructure and regulations that apply in each country or region.

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Written Testimony
Of

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before the

Committee on Finance
Subcommittee On Energy, Natural Resources, and Infrastructure
U.S. Senate

April 26, 2007

Chairman Bingaman, Senator Thomas, and Members of the Subcommittee: It is a privilege to testify before you today on the importance of maintaining coal as a vital source of energy for the production of electricity in our Nation and the importance of continuing Federal support for coal. As history has clearly shown, Federal funding of research and development and Federal tax incentives are catalysts to stimulate the development of innovative and cost-effective technologies that can address our country's energy and environmental concerns, such as the control of emissions from coal-fired power plants.

For the past 30 years, the scientists and engineers at ADA Environmental Solutions (ADA-ES) have built an international reputation for developing and commercializing highly efficient emissions measurement and control technologies for the power industry. Starting in 2000, we began to focus our efforts on research, development, and demonstration of technology for reducing mercury emissions. Today, we are the market leader in providing commercial equipment to capture up to 90% of mercury generated by the combustion of coal. These experiences demonstrate the importance of the right Federal involvement as this Subcommittee and firms such as ADA-ES begin to grapple with other challenges to our energy supply.

Our Testimony Today

Today we would like to give you our perspective of clean coal by discussing the following points:

1) Coal is critical to our future because it is reliable (base load capacity), inexpensive, abundant, and local.
2) The industry has demonstrated the ability to meet environmental challenges involving NO_x, SO_2, particulates and mercury.
3) Federal incentives, such as tax credits, have been effective in advancing technology to ensure realistic options exist and that the costs of these options are manageable.
4) Success for new technologies depends on a careful balance between:
    - Incentives for technological developments;
    - Sufficient time for risk mitigation; and
    - Regulation or tax-based market drivers (often referred to as "sticks" or "carrots").
5) CO_2 control seems to be the next concern for our nation's coal industry and the critical points are:
    - The scale is massive;
    - The timeframe is probably long -- 10 to 20 years;
    - Sufficient investment is critical;
    - Success is likely; and
    - Investment and incentives need to be designed to ensure that multiple technological paths are followed and that costs and risks are reduced.

Coal Is Critical To Our Future

As an environmental technology company, ADA-ES believes that the continued use of coal is critical for sustainable and reliable power generation in the U.S.

America leads the way in environmentally beneficial technologies. As a result of tightened regulations, we continue to improve technology so that the air we breathe and the water we drink are cleaner. We reap these related health benefits because our nation's strong economy allows us to allocate significant resources to these efforts. Much as our country demands higher air and water quality standards, we also need power generation that is inexpensive, reliable, and secure. Coal meets these needs. Today, more than 1,100 coal-fired boilers produce more than 50% of our nation's electricity. Figure 1 illustrates the strong correlation between the use of coal and the ability to provide inexpensive electricity.

Electricity is a much more valuable commodity than it has ever been. Coal plants have increased operational capacity from 59% in 1990 to between 80% and 85% in 2006. The U.S. is expected to need 50% more electrical capacity by 2030. To meet this need, the reliability of coal-fired power plants must continue to improve.

Economic development requires enormous investments in all aspects of energy infrastructure and significant increases in power generation. This is the motivation that drives us to optimize our current investment. We really have no other choice, as it would take decades to replace our current infrastructure.

Any expansion of power supplies must recognize that no single energy source can meet this need -- it requires a portfolio of solutions, including efficiency gains, more renewables, new nuclear power capacity and new coal-based generation. As renewables, such as solar and wind power, become a greater portion of our energy mix, it becomes more important to maintain a source of reliable power that can operate continuously in all weather conditions.

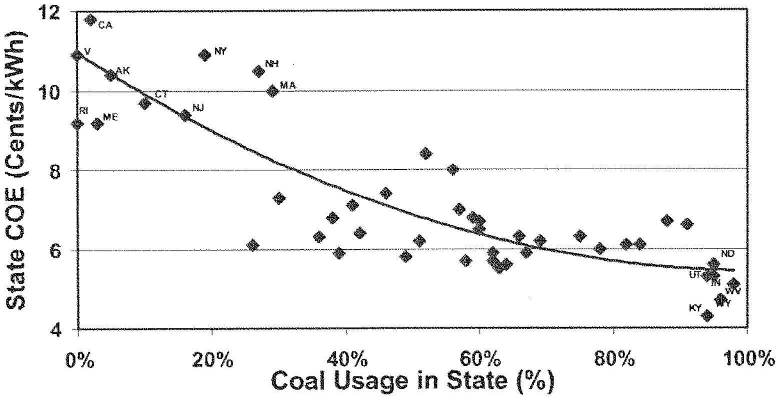

Figure 1. Cost of Electricity in a State as a Function of the Percentage of Electricity Produced from Coal.

Coal can also play an important role in national security by reducing our dependence on foreign energy sources. The United States has the largest coal reserve in the world, and have more coal than any nation has of any single energy resource. At current consumption rates, these coal reserves could supply our nation with 250 years of fuel. This is far greater than our reserves of natural gas and oil combined.

For these reasons, coal remains an essential part of the U.S. generation mix as a secure, plentiful, and relatively inexpensive fuel source. However, we as a nation must determine how to continuously improve emissions. Our goal needs to be "clean coal".

Clean Coal Background

The emissions control industry has made huge advancements in technology to improve emissions from coal-fired power plants. Collaboration among research organizations, universities, and power generation partners has enabled emissions of criteria pollutants sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates from the existing fleet of coal fueled power plants to be lower today than they were in 1970, even as power produced from coal plants has increased by 173% (See Figure 2).

Reductions in NOx, SO_2, and particulate emissions were driven by a balance between technology development incentives and emissions regulations. As an example, in the early 1970's, flue gas desulfurization equipment, commonly referred to as "scrubbers," were new and suffered from poor reliability and performance. Over time, as experience was gained and equipment modified, efficiencies rose from about 70% SO_2 removal to 95% to 98% today, with similar improvements in reliability. The emissions of criteria pollutions shown in Figure 2 will continue to decrease each year as emission control equipment is installed on more plants as a result of new regulations such as the Clean Air Interstate Rule.

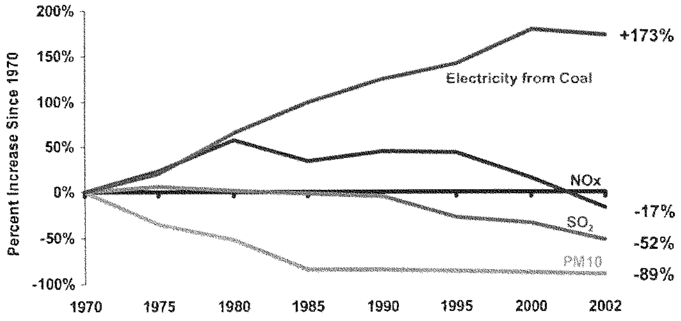

Figure 2. NO_x, SO_2, and particulate emissions from coal-fired power plants continue to decrease even as we increase production significantly.

Challenges in Developing New Emission Control Technology for the Power Industry

To understand how to make coal cleaner, it is helpful to appreciate how emissions control technology has developed for this industry. Since the first Clean Air Act of 1970, the power industry has gone through several rounds of implementing emissions control technology for NO_x, SO_2, and particulates. In each case, there were very similar experiences as new technology was applied in an industry where reliability and compliance are mandatory. We learned the following important lessons:

- Be prepared for unexpected reactions between flue gas constituents and chemical reagents used to control the pollutants;
- Do not underestimate the differences in coal and plant operating conditions to cause wide variations in emissions;
- Try to plan for significant O&M problems that might not show up until after long-term operation; and
- Look for secondary effects on other components of the power plants.

In each case, new-technology challenges had a significant impact on the reliability of power generation. The plants were forced to operate at reduced loads and suffered many unplanned shutdowns for maintenance and repair. Over time, technologies were improved to an acceptable level of cost and reliability. This is the true measure of acceptance, although significant risks may remain depending on how widespread the technology was applied during the early adopter phase. For example, Hot-Side Electrostatic Precipitators (for particulate control) have cost the industry over a billion dollars. After initial successes, the technology was quickly applied to 150 power plants only to have a fatal flaw subsequently discovered.

One of the challenges with implementing new emissions control technology is that the scale is massive. For example, emissions control equipment for a 500 MW plant treats two million cubic feet of flue gas every minute. Scrubbers may be as large as the power plant to which they are attached. Imagine the complications involved when we need to add new emissions control technology without taking the plant off-line.

We have learned that the best way to bring new technologies to an existing coal-fired power plant is to proceed through a carefully chartered course:

1. Laboratory testing: Provides a cost effective means to determine general feasibility and test a variety of parameters.
2. Pilot-scale: Test under actual flue gas conditions but at a reduced scale.
3. Full-scale field tests: Scale up the size of the equipment and perform tests under optimum operating conditions to define capabilities and limits of the technology.
4. Full-scale field tests at multiple sites: Each new site represents new operating conditions and new challenges.

5. Long-term demonstrations at several sites: Some problems will not show up until the first year or so of operation.
6. Widespread implementation: Problems will still be found at new sites, but most of the fatal flaws will have already been discovered and resolved.

We know from experience that trying to accelerate technology development by skipping these steps can result in large-scale operating problems and untimely and expensive plant outages. We also know that it takes ten to twenty years to successfully implement a major technology in this industry and implementation presents significant risks to the developer and user at each stage. In addition to the technology risk, there is significant financial risk to the developer. This is especially true when there is no regulation to guarantee a market will exist for a technology to control an emission that has not been previously regulated. There is often a "chicken and egg" dilemma in which there is no regulation to incentivize the development of a new technology and therefore there is no technology on which to base a regulation. Such was the case in the recent past, when the power industry was faced with reducing mercury emissions for the first time as discussed below.

ADA-ES Experience in Developing and Implementing Mercury Control Technology

It is instructive to present a case study on how Federal initiatives effectively provided incentives and risk mitigation that allowed industry to successfully develop cost-effective mercury control technologies for coal-fired power plants.

Methylmercury, which builds up in certain fish, is a neurotoxin that leads to developmental problems in fetuses of pregnant women. Mercury contained in coal represented the largest man-made source of mercury. In December 2000, the Environmental Protection Agency announced that it was beginning to consider regulating mercury emissions from the nation's coal-fired power plants.

In anticipation of future regulations, the Federal government and industry funded research to characterize the emission and control of mercury compounds from the combustion of coal. Some estimates showed that 90% mercury reduction for utilities would be expensive for the industry because of the large volumes of gas to be treated, the relatively low mercury concentrations, and the difficulty of capturing certain species of mercury in its vapor phase.

With potential regulations rapidly approaching, it was important to concentrate efforts on the most mature retrofit control technologies. Injection of dry sorbents such as powdered activated carbon (PAC) into the flue gas and further collection of the sorbent by ESPs and fabric filters represented potentially the most cost-effective control technology for power plants.

The Department of Energy (DOE) realized the criticality of demonstrating and optimizing scale-up of sorbent injection technology to provide performance data for regulations. The DOE National Energy Technology Laboratory cost-shared these demonstrations, with additional funding from several power companies, the Electric Power Research Institute, and private ADA-ES funding.

The DOE-supported field tests resulted in great advances in technologies to capture mercury emissions and decreased costs. A 2005 report by the DOE Energy Information Administration concluded that because technology for 90% mercury control from Western (Powder River Basin) coals was not available, an overall 90% mercury control rule could cost $358 billion. However, use of these new technologies later demonstrated that the 90% reduction for PRB coal could be achieved for less than $1 billion per year. This saving represents a huge return on the investment made by the Federal government in supporting early development and demonstration of mercury control technology.

This success has allowed a dozen states to take mercury control into their own hands and implement stringent regulations on power plants in their respective states. This action has created the first real commercial market for the new mercury control technology.

Refined Coal Tax Credit (Section 45)

Tax incentives also play a vital role in achieving even further emission reductions. The 2004 American Jobs Creation Act included a production tax credit designed to incentivize clean coal at the front end -- changing the way the coal burns - for older plants with limited resources or space to add back-end emission control. The tax credit was written with clear emissions reduction goals: 20% NO_x reduction and either 20% mercury or SO_2 reduction. An additional market value test, requiring that the product result in a 50% increase in market value over the feedstock coal still needs clarification (e.g., a baseline determination), but the credit is significant in that it represents a strong goal-oriented, rather than specific technology-driven, tax incentive.

ADA-ES responded to the incentive of the tax credit and assembled a team to apply mercury control expertise to invest in technology development for a refined coal product that will allow older cyclone boilers to reduce mercury emissions by 90% -- enough to meet stringent state regulations -- simply by burning refined coal. Clarification on the market value test will allow us to move to full-scale demonstrations to optimize and deploy our refined coal technology, and realize the goals Congress intended by the legislation.

Clean Coal: Carbon Challenges

Carbon, in the form of carbon dioxide (CO_2), is a greenhouse gas that contributes to climate changes. Our goal is to reduce CO_2 from both new and existing coal-fired power plants. This presents a number of challenges for technology development. It is not our purpose to detail the technologies being advanced to address these issues - there will be a comprehensive report issued by the National Coal Council this summer that will provide in-depth background on the various approaches. Instead, we would like to briefly note three key areas for technology development.

1) First, increased efficiency. The most effective way to quickly decrease carbon emissions is to increase efficiency of power production on new and existing boilers. Today we have more than 1,100 coal-fired boilers in the U.S. with an average age of 45 years. When many of these plants were built during the 1950's and 1960's, we did not care much about efficiency because coal was readily available, and inexpensive.

Figure 3 shows that we produce 25% less CO_2 as boiler efficiency increases from 35% to 50%. That is 25% less carbon that we have to separate and sequester. In May 2001, the National Coal Council produced a report that identified technologies that could increase the amount of electricity from the existing fleet of coal plants by 40,000 MW in a three-year period. Those recommendations remain viable today. To increase the amount of electricity generated by the existing fleet by 40,000 MW without the need to build a single new plant of any fuel type represents a tremendous greenhouse gas mitigation opportunity for this country.

However, although increased efficiencies result in lower CO_2/MW-hr, it also requires higher investment per mega watt-hour. At present, there is no incentive to absorb these increased costs for reducing carbon dioxide emissions.

2) Carbon separation. Nitrogen comprises 78% of the flue gas from a coal-fired power plant. We have to separate the carbon from the nitrogen. Known technologies to do so include oxygen-fired combustion and amine (MEA) scrubbing for pulverized coal (PC) boilers, or chemical separation for integrated gasification combined cycle (IGCC) systems. The challenges now relate to scale and cost with this technology.

3) Carbon storage and sequestration. Once the carbon is separated, we must store, or sequester, it. Known technologies to do so include injection for enhanced oil recovery (representing only a small percent of CO_2), deep well injection, and deep ocean injection. The biggest challenges are the unknown long-term effects, which will determine long-term ownership and legal liabilities. Transportation of CO_2 from plants to storage sites will require large and expensive infrastructure development.

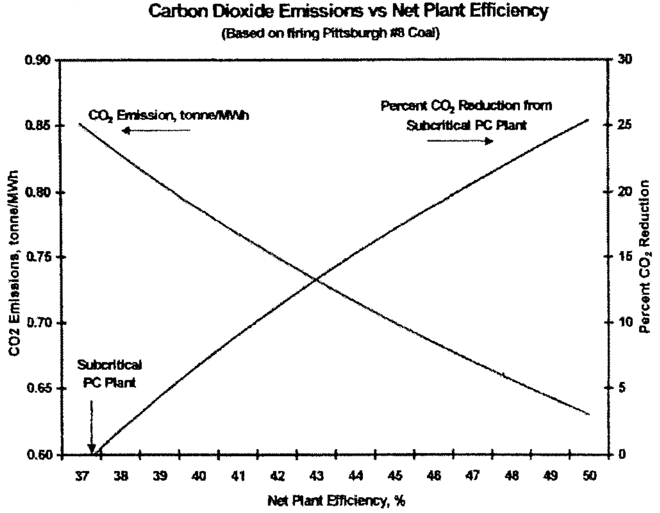

Figure 3. CO_2 emissions as a function of Net Plant Efficiency.

The Size of the CO_2 Problem

Carbon dioxide emissions from coal-fired power plants are bigger than anything our industry has experienced in the past. The average 500MW plant produces 900,000 lbs of CO_2 per hour, and for a typical PC boiler, this CO_2 is highly diluted in the flue gas. Compare this amount of CO_2 to about 0.01 lbs of mercury per hour for the same plant. The scale for carbon capture and storage technology is daunting and the costs will be high.

Technology maturation for carbon capture and storage will take time and the technologies are in their infancy. However, based on advances to date, they should become available and less costly, within the next 20 years or sooner. Carbon capture and storage technologies can be expedited, but they cannot be willed into existence overnight by changes in policy. CO_2 emissions from the U.S. are only a fraction of the world's carbon emissions. Technology developed in the U.S. can be transferred to countries like China and India that will allow the U.S. to leverage its investment in technology development.

New Coal-Fired Generation

Utilities are designing new coal-fired power plants to incorporate carbon separation and capture technologies as they become available. New coal plants will include both supercritical and ultra-supercritical PC boilers, as well as IGCC systems. They will incorporate the same carbon separation and storage technologies described above.

The Role of Carrots and Sticks in Encouraging Investment in Technology:

Not Choosing a Winning Technology

Coal-fired electricity is cleaner today as a result of a balance between "carrots" (e.g., government-funded technology development or tax incentives) and "sticks" (e.g., government regulation or restrictions). It is ineffective to impose the stick until technologies are ready, or nearly ready. Carrots, of course, will help speed up this process. In promulgating carrots and sticks, it is also important that the government defines a goal (e.g., reduced carbon emissions), but does not choose winning technologies. This notion is supported by most recent collaborative studies on reduced carbon emissions. For example, the 2007 MIT Interdisciplinary study, "The Future of Coal," suggests that the government must not select specific technologies, but rather should incentivize technology development towards a common goal.

Timing is Critical: If we impose clean coal restrictions (e.g., in the form of carbon taxes or emission limits) before separation and storage technologies are available, electricity costs will spiral, unraveling our economy and our ability to afford new technologies. However, history has demonstrated that if we first incentivize technology development, provide for risk reduction, and carefully time restrictions, the market will develop and provide winning technologies.

Summary

Clean coal is an important and viable part of our energy future. To move coal into a carbon-constrained world, we need to:

- Preserve base load electricity-generating capacity with reliable, inexpensive sources.
- Balance base-load capacity with renewable sources.
- Carefully balance timing between the carrots (e.g., tax credits and technology development funding) and the sticks (e.g., regulations).
- Incentivize the achievement of goals, not specific technologies (i.e., we should reward any carbon reduction, not just the known technologies to do so).
- Encourage more technology development (R&D tax credits, demonstration tax credits, etc., and coordination with DOE R&D funding).

We need to invest now in tax incentives and support for technology development. We do not know enough, yet, to decide which technology will be most cost-effective for each particular facility. Following multiple paths will increase the likelihood of sufficient successful options for application in the future, and will not preclude out-of-the-box technologies that have not yet been envisioned.

We believe that, based upon our past accomplishments, given sufficient resources and incentives, we can make clean coal a reality.

Thank you for your attention to this important National matter. We look forward to working with the Subcommittee and the Congress in meeting the challenges ahead. We would be happy to provide any additional information, analysis, etc., that you or your staff require.

UNITED STATES SENATE SUBCOMMITTEE ON ENERGY, NATURAL RESOURCES, AND INFRASTRUCTURE

Finance Subcommittee on Energy Hearing

Coal: A Clean Future

April 26th, 2007

Written testimony by
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Carbon Capture, Sequestration and Enhanced Oil Recovery: Potential Opportunities and Barriers in the Context of Geologic and Regional Factors

Outline of this Written Testimony
Executive Summary
Section 1: Potential Incentives for Geologic CO_2 Sequestration
Section 2: Potential Barriers and Restrictions for Geologic CO_2 Sequestration
Section 3: A Brief Primer on Geologic Carbon Sequestration Concepts – please refer to this section for more details about sequestration and the technologies discussed in Sections 1 and 2.

Carbon Capture, Sequestration and Enhanced Oil Recovery: Potential Opportunities and Barriers in the Context of Geologic and Regional Factors

Executive Summary

Thank you for the opportunity to testify about potential incentives and barriers associated with carbon capture and sequestration. My name is Brian McPherson and I specialize in geology, geophysics and subsurface hydrology. For the past 10 years, I served as a professor of hydrogeology at New Mexico Tech. For the past 3½ years I have served as PI and Director of the Southwest Regional Partnership on Carbon Sequestration, a consortium sponsored by the U.S. Department of Energy along with six other regional partnerships. At this time, I am employed at both New Mexico Tech and the University of Utah.

The general premise of geological CO_2 sequestration is to

(1) separate CO_2 from power plant flue gases,
(2) capture that CO_2 in a separate stream,
(3) compress the CO_2 to elevated pressures to maximize its density,
(4) inject the CO_2 into subsurface geological formations ranging from 2,500 to 20,000 feet depth.

Target storage reservoirs are porous and permeable rock layers, overlain by low-permeability confining layers. Such geologic reservoirs have contained brine, oil and natural gas for millennia, and thus using these reservoirs for storing CO_2 is a very viable concept. Target reservoirs are commonly classified by what type of fluid they hold, including:

- *Depleted oil and gas fields:* Injection of CO_2 into these reservoirs can enhance oil recovery (EOR) or gas recovery (EGR);
- *Deep unmineable coal seams*: Injection of CO_2 into these reservoirs can enhance gas recovery (EGR);
- *Deep saline formations*: classified as reservoirs with brine salinities greater than 10,000 ppm; injection into these reservoirs is preferred by many because the brine is not useable for other purposes.

With a robust confining layer, sequestration duration can be maximized and risk minimized. With respect to engineering, such CO_2 injection has been done for decades in many areas of the U.S., for enhanced oil recovery. Thus, the engineering and technological details are relatively mature.

At the moment, 25 field geologic sequestration demonstration tests are being designed and scheduled for deployment in the U.S. over the coming 3 years. An additional 20 or so are ongoing or slated for deployment soon in other countries. Most of these tests are using different technologies, including different engineering designs, different monitoring approaches, different risk assessment protocols and different mitigation strategies. And, most of these tests are relatively small in scale: small injection rates compared to typical power plant emissions output. The uncertainties associated with evaluation and design of large-scale sequestration operations are significant. For large-scale geologic sequestration to be deployed and sustainable over the long-term, a realistic, field-based evaluation of uncertainties, and how these uncertainties affect risk assessment and mitigation strategies, must be carried out. Additionally, the community also needs a meaningful assessment of CO_2 trapping mechanisms and the physical and chemical factors that may cause the mechanisms to lose efficacy under realistic (field) conditions. Next year, the U.S. will begin deployment of several commercial-scale sequestration deployment demonstrations. These will sequester up to 1 million tons/year, the scale of a typical power plant's emissions, with a scheduled duration of 5+ years. These tests will provide a good deal of the data required to maximize storage capacity and minimize uncertainty associated with commercial-scale sequestration, but not all of it. Therefore, I suggest that incentives may be needed to provide the huge amount of data needed to ensure commercial sequestration is robust and safe. Furthermore, I suggest that new incentives are needed to motivate industry to take on commercial sequestration as a routine part of business. I list these suggestions here.

(1) First, I recommend incentives that will stimulate sequestration operations, with some assigned greater priority than others. Specifically: I suggest that greatest priority and incentives be assigned to deep saline formations underlying oil/gas fields, to maximize relevant characterization data availability and monitoring opportunities. Next in the priority list would be deep saline formations not underlying oil/gas fields. Finally, the priority list and incentive ranking should include CO_2 injection in oil and gas reservoirs with maximized sequestration and minimized CO_2 recycling.
(2) I recommend incentives that will assist with providing the data necessary for liability, risk and capacity assessments associated with sequestration. Specifically, oil/gas and other entities hold a huge amount of data privately, and these data are essential to providing robust assessments of capacity and risk. The DOE's Regional Partnerships, in collaboration with state geological surveys and the USGS, are gathering a great deal of data and assembling them for the public in the form of NATCARB, a national carbon sequestration database. If added, privately held data would likely more than double the size of that database, and as well would double our ability to assess capacity and risks of sequestration.
(3) I recommend that areas of the country that lack CO_2 pipeline infrastructure be provided incentives for building such pipelines. For commercial-scale sequestration to move forward, infrastructure will be necessary.
(4) I recommend incentives for state-, federal- or privately-sponsored indemnification. The states of Illinois and Texas assembled comprehensive indemnification plans for FutureGen, and these plans may serve as a template for future liability associated with commercial sequestration.
(5) The U.S. lacks a fully resolved regulatory framework. Any planned incentives for sequestration and EOR should factor in the evolving regulatory framework being developed by the EPA, the Interstate Oil and Gas Compact Commission, the Regional Partnerships, and individual states.

Thank you again for this opportunity to speak to you today. I look forward to any questions you may have.

1. Potential Opportunities for Geologic CO_2 Sequestration

Enhanced Oil Recovery and Sequestration

In many areas of the United States, enhanced oil recovery (EOR) is a potential driver for carbon storage. The basic premise of CO_2-based EOR is to inject CO_2 into an oil reservoir, which will reduce the viscosity of oil and facilitate easier production. Some of the injected CO2 comes back to the surface with the produced oil, where it is separated from the oil and reinjected to continue the EOR process.

EOR generates profits from the sale of the produced oil. As a result it is a strong motivator for carbon storage and should be encouraged. I would like to see incentives for companies to maximize the ultimate storage of carbon dioxide in these reservoirs at the end of a field's useful life. While there is a small possibility for CO_2 to leak to the surface through abandoned wells, this drawback can be offset through regulatory and monitoring requirements.

Deep Saline Formation Sequestration

The capacity of deep saline formations – these are deep rock units filled with water which contains high levels of salts and minerals and is well below drinking quality standards – in sedimentary basins tends to be much greater than that for typical oil/gas fields, and thus these are preferred targets for sequestration. Additionally, oil and gas fields have the potential of CO_2 leakage because of abandoned wells, as mentioned above, whereas deep saline reservoirs possess few or no such wells.

Since deep saline formations represent a low-risk, high capacity storage site for CO2, I recommend using tax incentives or other means to stimulate storage in these formations. EOR has the built-in profit incentive from the sale of incremental oil. Perhaps the incentives for deep saline formations could offset this built-in advantage.

However, I suggest that the best deep saline formations for sequestration are those that lie beneath oil and gas fields. The reasons for this are many:

(1) Areas with oil and gas fields tend to have more data associated with them, driven by previous or ongoing oil and gas exploration, whereas areas not prone to oil gas have sparse, if any, data. Data enable us to better characterize the area, which gives us greater certainty that the CO2 will stay where it was injected.

(2) Oil and gas fields tend to have infrastructure to transport and inject CO_2 locally, including pipelines or at least existing pipeline rights-of-way.

(3) Oil or gas reservoirs, especially active ones, may be monitored for CO_2 that may leak from the target saline formation below. Because of its low density, CO_2 will always migrate vertically towards the surface, and in this scenario will reach the oil/gas reservoir first. Tracers, if needed, may be injected with the CO_2 to provide a means of detecting the CO_2 if it moves into the oil/gas reservoir. This effectively provides an early-warning system that the CO2 is not staying in the targeted reservoir.

Thus, perhaps the greatest incentives could be instigated for deep saline reservoirs beneath oil/gas fields. In sum, I recommend that incentives be provided to stimulate sequestration operations, prioritized according to the high-to-low order below:

(1) deep saline formations underlying oil/gas fields, to use available relevant data to characterize the target formation and provide monitoring opportunities. Additionally, negotiating mineral rights, water rights, and "pore ownership" associated with

sequestration will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.

(2) deep saline formations not underlying oil/gas fields

(3) oil and gas reservoirs with maximized sequestration and minimized CO_2 recycling (i.e., minimize use of re-produced CO_2 for continued EOR).

2. Potential Barriers and Restrictions for Geologic CO_2 Sequestration

The Pipeline Differential

Adoption of sequestration requires not just good geology, but also pipelines. Pipelines are necessary to transport the vast amounts of CO_2 to be sequestered. A typical coal-fired power plant produces 1 to 15 million tons of CO_2 per year, and the ideal sequestration reservoir may be tens to hundreds of miles away. The southwestern U.S. enjoys a limited CO_2 pipeline network for transporting CO_2 from natural CO_2 reservoirs in southern Colorado and New Mexico into the Permian Basin of western Texas for EOR. The presence of this existing pipeline infrastructure is facilitating numerous medium- to large-scale sequestration pilot demonstrations, and is also providing a basis for planning future commercial sequestration operations by several major electric utilities in the region. For example, discussion focuses on using these major pipelines for linking CO2 sources (power plants) with the best CO2 storage sites.

However, in other parts of the country, planning for commercial sequestration is hampered because of the lack of such pipeline infrastructure. Commercial operations will likely go forward in these areas – the geology is good for carbon sequestration – but pipeline costs currently exceed $20,000 to $50,000 per mile, severely limiting their expansion.

In sum, providing incentives for areas without existing pipelines could help stimulate the infrastructure development necessary for long-term commercial sequestration possibilities. If large-scale commercial CO_2 sequestration is to become a reality, regional and/or national CO_2 pipelines that mimic the natural gas pipeline infrastructure will be needed.

Liability for sequestered CO_2

Liability of CO_2 capture and geological sequestration is generally classified into (a) operational liability and (b) post-injection liability. For both types of liability, I recommend that ownership and liability should be one and the same, i.e., whatever entity takes ownership also takes liability.

If a State takes on liability, then that state could own the CO_2; likewise for a private company. In many states, especially oil-producing states, CO_2 is a commodity, and therefore most liability-holders will probably want to own the CO_2. In some states, CO_2 may not be as valuable a commodity, and in this case private or state/federally sponsored insurance may be preferred.

Regardless of whether liability protection is provided by state, federal, or private entities, the scale of liability costs will be determined by the amount of data available to characterize a sequestration site's capability to retain CO_2 and to evaluate and provide quantified risk assessments. The more data that are available and useable, the lower the likely liability cost. Liability characterization frameworks are being developed by the U.S. Department of Energy's Regional Partnerships, and this work is being done in collaboration with federal agencies, including the U.S. Geological Survey.

In order to maximize participation in this process, I recommend that private companies be encouraged to provide their oil/gas or other subsurface geological information to the federally sponsored NATCARB databases. These data are necessary to determine the liability protection necessary for different sequestration sites.

I also recommend federal involvement in developing protocols that provide indemnification at a State or federal level for the ultimate fate of the sequestered CO2. Such a program could be instigated with a formal classification of liability "level," the value of which to be determined by the data available to characterize a site and its risks. As mentioned previously, the U.S. Department of Energy's Regional Partnerships are collaborating with the U.S. Geological Survey and other entities to draft such a classification system.

Capacity and Risk Assessments

As mentioned above with respect to liability, comprehensive fundamental geological data are required to evaluate risk and ultimate levels of liability protection requirements. These data are also necessary for accurate estimates of reservoir CO_2 capacities throughout the U.S. The U.S. Department of Energy's Regional Partnerships finished an initial assessment of subsurface and surface (terrestrial/vegetation/soil) storage capacity, and will continue updating this assessment annually for the coming decade. More data are being collected every week, populating a national database of geologic sequestration data, also known as "NATCARB." Local, regional and national capacities are continually being updated, and this work is carried out in collaboration with the U.S. Geological Survey and a collective of individual State Geological Surveys. The Regional Partnerships and the U.S. Geological Survey are working together at this time to identify how the U.S.G.S. can best complement the ongoing Partnerships program.

Regulatory Uncertainty

At this time, the regulatory frameworks for carbon capture and sequestration are still evolving. The final regulatory regimal will greatly affect the ultimate success of commercial-scale carbon sequestration. I list below many rules/regulation topics that possess some uncertainty, and provide some suggestions for these:

1. Agency regulatory authority: I recommend that individual states assign sequestration regulatory efforts to current oil/gas regulatory agencies at the state level. The State oil and gas agencies in many States are currently administering CO2 injection for EOR through the EPA's Underground Injection Classification program.
2. Ownership of pore-space and rights to sequester: I recommend that individual states implement pore-space/rights ownership to be similar to existing oil/gas frameworks (e.g., as an example or template or model). Negotiating pore-space ownership and rights to sequester will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.
3. Mineral and water rights: I recommend that individual states implement pore-space/rights ownership to mimic existing oil/gas frameworks (e.g., as an example or template or model). Negotiating mineral and water rights associated with sequestration will likely be easier in formations within and under oil/gas fields, because such rights in these areas were previously evaluated, in general.
4. Radius of influence and regulation of injection volumes: I recommend that individual states make radius of influence to be similar to existing oil/gas frameworks (e.g., as an example or template or model).

5. Need for unitization or eminent domain: I recommend that individual states make unitization/eminent domain to be similar to existing oil/gas frameworks (e.g., as an example or template or model).
6. Mechanical integrity of injection wells and legacy wells penetrating sequestration reservoir: I recommend that legacy wells and mechanical integrity be regulated strictly (more strictly than oil/gas wells), because of the liability and risk associated with well breakdowns or failures.
7. Well injection pressure limitations: I recommend that pressure limitations be at most 80% of least principal stress (also known as the "fracture pressure" or "fracture gradient").
8. CO2 Purity limitations and testing: I recommend 90% CO2 purity, minimum.
9. Enhanced oil recovery and sequestration: I recommend individual states encourage EOR and optimized/maximized sequestration, as outlined previously in this document.
10. Injection monitoring and reporting: I recommend rigorous monitoring and reporting standards, again because of liability and risk. The U.S. Department of Energy and its sponsored projects are developing guidelines and standards for monitoring and reporting.
11. Bonding: I recommend that individual states make bonding aspects to be similar to existing oil/gas frameworks (e.g., as an example or template or model).
12. Permitting: EPA has regulatory control, but should preferably delegate implementation to individual states agencies that already regulate oil/gas production and produced water disposal.
13. Closure (post-injection) monitoring and reporting: I recommend rigorous/strict closure monitoring and reporting (again, to account for liability and risk). The U.S. Department of Energy and its sponsored projects are developing guidelines and standards for minimum closure monitoring and reporting.
14. Surface owners rights: I recommend that individual states make surface rights for sequestration to be similar to existing oil/gas frameworks (e.g., as an example or template or model).

3. Brief Primer on Carbon Sequestration Concept

At the moment, 25 field geologic sequestration demonstration tests are being designed and scheduled for deployment in the U.S. over the coming 3 years. An additional 20 or so are ongoing or slated for deployment soon in other countries. Most of these tests are using different technologies, including different engineering designs, different monitoring approaches, different risk assessment protocols and different mitigation strategies. And, most of these tests are relatively small in scale: small injection rates compared to typical power plant emissions output. The uncertainties (error) associated with evaluation and design of large-scale sequestration operations are significant. For large-scale geologic sequestration to be deployed and sustainable over the long-term, a realistic (field-based) evaluation of uncertainties, and how these uncertainties affect risk assessment and mitigation strategies, must be carried out. Additionally, the community also needs a meaningful assessment of CO_2 trapping mechanisms and the physical and chemical factors that may cause the mechanisms to lose efficacy under realistic (field) conditions.

The purpose of this brief primer section is to summarize CO_2 sequestration concepts, from the macro-scale general operation to micro-scale trapping mechanisms.

Macro-Scale: Geological CO_2 Sequestration

The general premise of geological CO_2 sequestration is to

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(6) capture that CO_2 in a separate stream,
(7) compress the CO_2 to elevated pressures to maximize its density,
(8) inject the CO_2 into subsurface geological formations ranging from 2,500 to 20,000 feet depth.

Target storage reservoirs are porous and permeable rock layers, overlain by low-permeability confining layers (Figure 1). Such geologic reservoirs have contained brine, oil and natural gas for millennia, and thus using these reservoirs for storing CO_2 is a very viable concept. Target reservoirs are commonly classified by what type of fluid they hold, including:

- *Depleted oil and gas fields:* Injection of CO_2 into these reservoirs can enhance oil recovery (EOR) or gas recovery (EGR);
- *Deep unmineable coal seams*: Injection of CO_2 into these reservoirs can enhance gas recovery (EGR);
- *Deep saline formations*: classified as reservoirs with brine salinities greater than 10,000 ppm; injection into these reservoirs is preferred by many because the brine is not useable for other purposes.

With a robust confining layer (Figure 1), sequestration duration can be maximized and risk minimized. With respect to engineering, such CO_2 injection has been done for decades in many areas of the U.S., for enhanced oil recovery. Thus, the engineering and technological details are relatively mature.

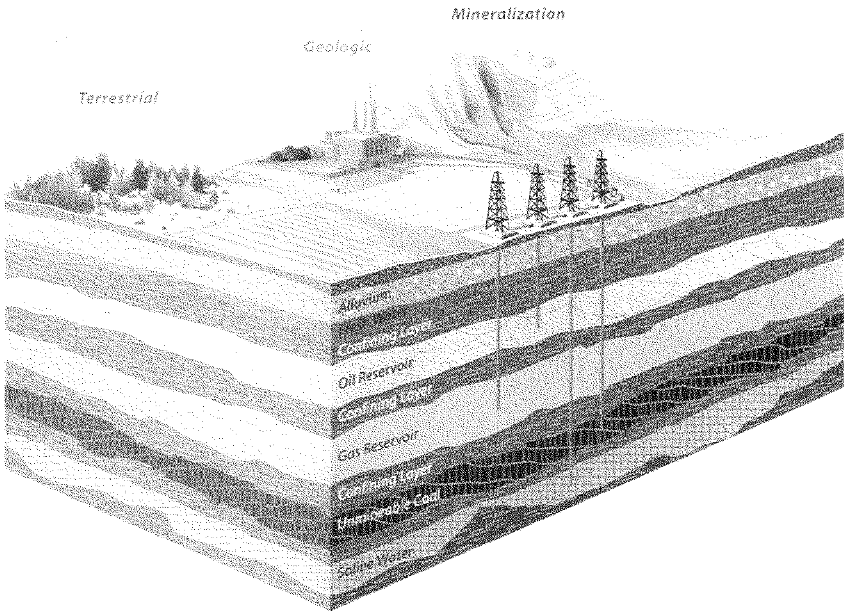
Micro-Scale: CO_2 Trapping Mechanisms

In this primer I describe the four primary geologic trapping mechanisms, including hydrostratigraphic, residual gas, solubility, and mineral trapping. Potential failure modes of each trapping mechanism are outlined, including discussion of how to define uncertainty of these failure modes.

Hydrostratigraphic Trapping

Hydrostratigraphic trapping refers to trapping of CO_2 by low permeability confining layers (Figure 1). This type of trapping is often distinguished by whether the CO_2 is contained by stratigraphic and structural traps, e.g., similar to oil and gas reservoirs, called static accumulations, or whether it is trapped as a migrating plume in large-scale flow systems, called hydrodynamic trapping. In general, CO_2 is trapped in permeable rock units in which the fluid flow is constrained by upper and lower less-permeable "barrier" lithologies. Such top and bottom seals are often formed by shale or salt units; lateral flow barriers may be due to facies changes or to faults. Faults and fractures may affect fluid flow; in some cases faults/fractures may be sites for preferential fluid flow, whereas in other cases they may inhibit fluid flow. Deep saline units typically have large lateral extents, while oil and gas reservoirs are typically much smaller. Although reservoirs may be classified by the nature of trapping mechanism, the geologic community tends to distinguish them on the basis of rock type.

Figure 1. Sequestration options: (1) terrestrial sequestration, including changes in land-use and tillage practices that increase carbon-uptake by soils and vegetation, (2) geologic sequestration, including injection and storage in deep saline formations, oil/gas reservoirs, and coalbeds, with a confining layer above to keep CO_2 in place, and (3) mineralization, which involves converting CO_2 to mineral precipitates, such as limestone. Geologic sequestration is the most economic, as it provides the greatest capacity for its cost. Terrestrial provides relatively low capacity, while mineralization is prohibitively expensive at this time. Figure provided by the Southwest Regional Partnership on Carbon Sequestration (and drafted by the Colorado Geological Survey).



Residual Gas Trapping

At the interface between two different liquid phases (such as CO_2 and water), the cohesive forces acting on the molecules in either phase are unbalanced. This imbalance exerts tension on the interface, causing the interface to contract to as small an area as possible. The importance of this interfacial tension in multiphase flow is paramount; the multiphase CO_2-brine-oil-gas flow equations are more sensitive to interfacial tension than many other fluid properties. Interfacial tension may trap CO_2 in pores, if fluid saturations are low. The threshold at which this occurs is called the "irreducible saturation" of CO_2, and is a key concept for defining "residual gas trapping." The magnitude of residual CO_2 saturation within rock, and thus the amount of CO_2 that can be trapped by this mechanism, is a function of the rock's pore network geometry as well as fluid properties. Geologic conditions that impact the amount of CO_2 trapped as a residual phase include petrophysics, burial effects, temperature and pressure gradients, CO_2 properties (density) under different P-T conditions, and on engineering parameters such as injection pressure, induced flow rates, and/or well orientation.

I view residual gas trapping as a secondary mode of sequestration relative to hydrostratigraphic trapping. Under this assumption, CO_2 would be injected for the purpose of hydrostratigraphic trapping, and residual gas trapping would be an additional process that renders the CO_2 immobile within hydrostratigraphic traps. Such an assumption has implications for evaluating possible failure modes and associated mitigation plans.

Solubility Trapping

Perhaps the most fundamental type of trapping is dissolution, or "solubility trapping." First, CO_2 dissolves to an aqueous species:

$$CO_2\,(g) + H_2O = H_2CO_3, \tag{1}$$

(relatively slow rates)

followed by rapid dissociation of carbonic acid producing bicarbonate and carbonate ions while lowering pH, or

$$H_2CO_3 = H^+ + HCO_3^- \tag{2a}$$

(relatively fast rate)

$$HCO_3^- = H^+ + CO_3^{--}. \tag{2b}$$

(relatively fast rate)

This leads to a series of additional reactions and "mineral trapping," discussed in the next section. The amount of sequestration possible through solubility trapping is very limited per unit mass of water, as groundwater (brine) can only dissolve up to a few mol% or less, depending on pressure (P), temperature (T), and salinity. Over large volumes of reservoir, solubility trapping may provide a significant amount of storage.

Mineral Trapping

"Mineral trapping" refers to the process of CO_2 reacting with divalent cations to form mineral precipitates in the subsurface. The reactions, especially reaction rates and associated processes that affect rates (e.g., complexation, pH buffering, etc.) are complicated and make estimates of CO_2 storage capacity difficult. However, mineral trapping is assumed to be a relatively safe mechanism that may sequester CO_2 for millions of years.

While mineral trapping may not be permanent, it can certainly render CO_2 immobile for very long time scales. The main source of uncertainty associated with mineral trapping are associated with the kinetic rate coefficients and reaction specific surface areas of minerals for the many homogeneous and heterogeneous reactions.

Potential Failure Modes

Hydrostratigraphic Trapping Failure Modes

All CO_2 trapping mechanisms have several failure modes. Critical objectives are to ascertain the physical and chemical processes of each failure mode and to minimize uncertainties in the characterization, and potential range of response, of those processes under sequestration conditions. Major failure modes for hydrostratigraphic trapping include:

(1) unintended migration by pre-existing but unidentified faults, fractures, or other fast-flow paths (e.g., Figure 1),
(2) unintended migration by stress-induced or reactivated fractures or faults,
(3) unintended migration by reaction-induced breaching of a seal layer
(4) unintended lateral flow to unintended areas,
(5) catastrophic events (e.g., unexpected earthquakes, etc.),
(6) wellbore failure events.

One approach to mitigating several of these failure modes is to select a storage site with multiple alternating seals and reservoirs above the primary (intended) reservoir, sometimes described as stacked reservoirs. However, even when stacked reservoirs are present, other measures must be taken to minimize risk of failure.

I view hydrostratigraphic trapping as the primary mechanism of CO_2 storage in subsurface geologic reservoirs. I suggest that the other trapping mechanisms, including residual gas trapping, solubility trapping, and mineral trapping, are specific modes of CO_2 storage within hydrostratigraphic traps. As such, the failure mechanisms for hydrostratigraphic trapping are of primary importance. I suggest that risk mitigation programs should make quantification of probabilities for hydrostratigraphic trapping failure modes a priority. However, under conditions of a failed hydrostratigraphic trap, I presume that leakage from an intended reservoir may lead to CO_2 movement into secondary hydrostratigraphic traps above the target reservoir/seal (e.g., stacked reservoirs), for example; in this case, residual gas trapping, solubility trapping, and mineral trapping all become mechanisms for helping to keep the CO_2 in place in the secondary reservoir. Additionally, if secondary reservoirs have no seal or hydrostratigraphic trap (in a strict sense), these other trapping mechanisms may provide an important overall damping of the flux of CO_2 back to the surface. Thus, although hydrostratigraphic trapping is priority, the other trapping mechanisms are still very important and uncertainty associated with each must be addressed.

Residual Gas Trapping Failure Modes

The primary failure mode for residual gas trapping is loss of capillary forces (surface tension) of the pore matrix. Such loss would be due to any process that changes the pore geometry or size or changes the interfacial tension, including compaction, dissolution or precipitation of cements in or around pores, or changing fluid composition. All of these processes require relatively long periods of time, and thus I suggest that risk is low for any of these to occur within timeframes of interest. Additionally, if these processes do occur, the most likely effect will be for CO_2 to dissolve into surrounding brine or to transition to free phase CO_2. At that point, the CO_2 is subject to the same set of trapping mechanisms for hydrostratigraphic trapping (recall that I assume the primary goal is hydrostratigraphic trapping, with residual gas trapping as a means of rendering CO_2 immobile within hydrostratigraphic traps).

Significant (large) changes in fluid pressure or temperature throughout the rock unit may change the fluid properties enough to reduce surface tension as well, although this is less likely to occur (low risk), or at the least is easier to monitor.

Solubility Trapping Failure Modes

The primary failure mode for solubility trapping is exsolution, which would only occur under significant (large) changes in pressure or temperature. As suggested above, the risk of major changes in pressure or temperature in a deep reservoir is very low, and monitoring for such changes over time is straightforward. Much like with residual gas trapping, I assume that the primary intended storage mechanism for geologic sequestration will be hydrostratigraphic trapping, with solubility trapping as one mode of storage within hydrostratigraphic traps. Following failure of solubility trapping, the CO_2 is still subject to the failure modes discussed under hydrostratigraphic trapping.

Mineral Trapping Failure Modes

The primary failure mode for mineral trapping is dissolution of the carbonate minerals that trapped CO_2. This is always a possibility, but much like for exsolution, this would take a great amount of time, and the surrounding brine would need to provide conditions that promote dissolution (e.g., low pH plus undersaturated with respect to bicarbonate for carbonate reactions). By monitoring the P-T and fluid composition through time, the status of mineral trapping and failure (dissolution and release of CO_2) can be easily monitored.

Much like with solubility trapping and residual gas trapping, I assume that the primary intended storage mechanism for geologic sequestration will be hydrostratigraphic trapping. Mineral trapping is therefore viewed as a means of rendering CO_2 immobile within hydrostratigraphic traps. Following failure of mineral trapping (dissolution and release of CO_2), the CO_2 is still subject to the failure modes discussed for hydrostratigraphic trapping.

Approach for Quantifying Uncertainty of Trapping Mechanisms and Failure Modes

I suggest an approach that includes three key components: (1) comprehensive integration of previous and ongoing basic research, (2) comprehensive assessment of previous and ongoing field demonstrations, and (3) a program of new laboratory and large-scale field testing. All three components are important for identifying gaps in the current state-of-the-art, for defining and calibrating appropriate phenomenological models, and for quantifying uncertainty of trapping failure modes. The U.S. Department of Energy through its Regional Partnerships program is carrying out several commercial-scale (1 million tons/year, the scale of a typical power plant's emissions) sequestration deployment demonstrations in the coming decade, with two or three of these to begin in 2008.

Quantitative assessment of geologic uncertainty is critical to success of sequestration. In the oil industry, several different approaches have been used to obtain probability distribution functions (PDFs) of desired parameters, such as hydrocarbons in place, recovery factors, etc. In CO_2 sequestration the community will employ such approaches for many facets of sequestration, for example, determiniation of critical fault properties that could lead to hydrostratigraphic trapping failure or to thickness variations of the seal that could lead to seal breach. High resolution data are needed for this effort.

Statement of Senator Craig Thomas, Ranking Member
Subcommittee on Energy, Natural Resources, and Infrastructure
Hearing on "Coal: A Clean Future"
April 26, 2007

First I'd like to thank all our witnesses for being here today. I look forward to your comments. I especially want to welcome Steve Waddington, Executive Director of the Wyoming Infrastructure Authority.

We are in an environment now where many are concerned about the prospect of global climate change, we are faced with finite fossil fuel resources, and many are focused on alternative energy sources. I understand and agree with the goals of a clean environment and development of alternative energy sources. However, I am also frustrated by the lack of recognition that, while renewable resources are likely to play a greater role in our future, fossil fuels are our present.

This is a very important point. Many of the renewable technologies are not ready for mass deployment to meet our country's current and growing energy needs. Coal, by contrast, already provides more than 50 percent of our country's electricity.

Frankly, coal gets a bad rap. Recently there was a full-page ad in a number of publications proclaiming "Coal is Filthy." This message merely reinforces the myth that using coal necessarily belches tons of harmful pollutants into the environment. In fact, technologies are well-developed to make coal not only very clean, but extremely versatile. These days we can burn coal cleanly to produce electricity; we can gasify it; we can liquefy it into diesel; we can even turn it into plastic or ethanol. A number of these technologies are in use already and commercially available.

I am also concerned that carbon dioxide emissions have become the standard by which environmental performance is judged. As humans, every time we breathe we emit carbon dioxide. Our livestock alone is responsible for 18 percent of greenhouse gas emissions. I've suggested that we take a more balanced approach toward how we view "pollution," its causes, and responsible ways to address it.

We're going to hear a lot today about CO_2 capture and sequestration. I would like to emphasize, however, that CO_2 is only a small part of the issue we have before us. In discussing the perceived threat of climate change and attempting to address it, we must not lose sight of options to improve the use of a reliable domestic resource like coal. I would like to remind my colleagues here today of the economic and tax revenue benefits associated with advancing these value-added coal conversion activities.

In Wyoming, we produce a lot of coal – 36 percent of the amount needed to keep the lights on in the United States. We shovel that coal, and we ship it all across the country. Mining coal has been a tremendous economic benefit to my home state of Wyoming, but I believe we can do better.

There is a real opportunity to develop a more value-added industry, using that coal resource as a feedstock. It is important that we identify and move forward with ways to improve the environmental performance of coal. I hope to hear from the witnesses today about these opportunities.

The purpose of today's hearing is to explore our opportunities with coal and how well tax incentives currently in place are working to encourage clean coal development and deployment.

I am hopeful that today's hearing will be instructive as to the costs and benefits of the various clean coal technologies and their relevance to our future energy policy.

Blue*Source*

A leading climate change portfolio

William L. Townsend

Chief Executive Officer

The Blue Source Companies

Testimony

Before the Energy Subcommittee of the Finance Committee

United States Senate

Hearing on

Coal: A Clean Future
Response of the Market to Global Incentives and Mandates for Clean Coal

April 26, 2007

Summary

Coal, an abundant and cost-effective energy source when used to generate power, is a major contributor of greenhouse gas emissions in the United States due to the release of carbon dioxide. It is forecasted that between 100 and 150 new coal plants may be built in the US over the next ten years in order to meet the growing electric power demand, thereby significantly increasing the release of greenhouse gases. Carbon dioxide emissions from these new coal-based plants could be reduced or eliminated by constructing power generation capable of producing higher-purity carbon dioxide emissions that can be separated and captured and made ready for transportation to geologic sequestration. Technology for retrofitting existing coal-based power generation to separate and capture carbon dioxide is being developed and tested. However, carbon dioxide separation, capture, and storage (CCS) technology for new and existing coal-based power generation is presently expensive and, in some cases, untested. While CCS in geologic sequestration appears to be a major part of the answer to managing US greenhouse gas emissions, bridging the gap between the present and expected emissions of carbon dioxide in power generation and the eventual development of a more cost-effective carbon dioxide separation and capture technology is a significant problem. Recent estimates of this gap suggest it may be as long as 40 years.

Our company does not see the gap to be as uneconomic as has often been suggested. Nor do we expect the gap to be as wide as many suggest, due to a combination of existing and expected CCS technology, existing and expected transportation and storage assets, and related economic drivers which support the current development of regional CCS infrastructure. However, legislated financial incentives and regulatory relief could hasten the bridging of the remaining gap and accelerate the carbon dioxide infrastructure needed to effectively manage the growth of carbon dioxide emissions in the next 20 years.

Testimony of William L. Townsend

CEO, the Blue Source Companies

Mr. Chairman and Members of the Committee, thank you for the opportunity to testify today on the subject of carbon capture and storage (CCS) as it relates to clean energy from coal and on the topic of potential incentives related to accelerating the development of a carbon dioxide infrastructure that supports CCS. My name is Bill Townsend. I am the Chief Executive Officer of the Blue Source companies (Blue Source or Company). I will offer some background on our companies that will describe our unique knowledge of CCS and carbon trading in the US and offer some commercial and structural observations that I hope will apply to the development of any incentive program Congress might consider for CCS and clean energy from coal.

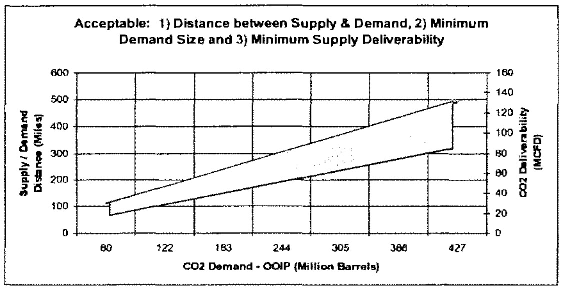
Unique Experience in CCS Infrastructure Development and Carbon Trading

Blue Source operates at the intersection of the energy and climate change industries. Our companies have significant knowledge and experience in developing anthropogenic (man-made) carbon dioxide (CO2) pipeline systems for geologic sequestration. Blue Source and its management team are in the unique position of having developed, designed, constructed, operated, and/or owned in one form or another all of the commercially developed, anthropogenic CO2-sourced pipelines for enhanced oil recovery (EOR) in North America during the last 20 years. These pipeline systems include the Val Verde Pipeline in West Texas, the North Cross Pipeline in West Texas, the Anadarko Pipeline in Wyoming, the La Veta Pipeline in Colorado, and the Dakota Gasification Pipeline in North Dakota. Collectively, these pipelines gather approximately 340 million cubic feet per day (MMCFD) (or 6.8 million tonnes [Mt] per year) of industrial vent stack-sourced CO2, and they deliver the CO2 for geologic sequestration in EOR operations in Canada, Wyoming, Texas, and New Mexico.

In addition to developing anthropogenic CO2 pipelines from industrial CO2 sources, Blue Source is the leading portfolio of greenhouse gas (ghg) emission reduction offsets in North America. The Company has on public registries throughout North America approximately 45 Mt of verified ghg emission reductions (ghg VERs) sourced from eleven different project types, which include, among others, transportation and logistics, fly ash substitution, geologic sequestration, methane avoidance and destruction, and energy conservation. In the case of geologic sequestration, Blue Source has led in the development of carbon market protocols and sold approximately 9 Mt of ghg VERs from its geologic sequestration projects to purchasers of the emission reduction offsets in both Canada and the US. The combination of our experience in developing anthropogenic CO2 CCS projects and marketing and selling ghg VERs from geologic sequestration, gives our company a unique view of the expected development of a US carbon dioxide infrastructure based on clean energy from coal.

Today, Blue Source is in various stages of evaluating and developing 13 different anthropogenic CO2 pipeline projects in North America, where the Company hopes to finance the separation, capture, transportation, and/or sequestration of approximately

1,400 MMCFD of CO2 (28 Mt per year), investing potentially $ 445 million over the next seven years. In order to finance this size construction potential, in late 2006 the Company partnered with a large private equity firm, First Reserve Corporation, to secure an investment pool dedicated to the carbon infrastructure development in the US. The chart in this text is one example of the Company's project screening tools which enables a quick analysis of a CO2 vent stack project's likely successful outcome. The chart is the practical representation of over 20 project feasibility variables, including gas and crude oil prices, steel and rights-of-way costs, construction cost rules-of-thumb, CO2 injection and reservoir characteristics, CO2 pipeline hydraulics, and other variables we have found to be significant determinants.



Over the past ten years, Blue Source and its affiliate companies have evaluated close to 100 vent stack-sourced CO2 projects in North America. The majority of these projects have had as their CO2 sources natural gas treating plants, fertilizer facilities, ethanol plants, and crude oil refineries. Only two IGCC power generation facilities and two coal-to-liquid facilities, all currently prospective projects, have been evaluated. While we are seeing more coal gasification projects on the horizon, we have not seen the necessary attention being given by the project developers (both public and private companies) to developing the carbon dioxide transportation systems and geologic sequestration sinks for the projects to go forward to completion. The primary reason only 5% of the projects we have evaluated during the last ten years have gone to the construction phase is because, even with EOR economics (oil-related revenues), the projects typically still yield a lower-than-acceptable investment return, though higher crude oil prices in recent years have certainly helped. A case in point is our La Veta CO2 Pipeline, which, for the last five years, did not have sound economics for construction; but with the recent improvements in crude oil values, it was finally constructed in 2006 and is expected to begin flowing CO2 around June 1, 2007. (It has been venting CO2 to the atmosphere.) If Blue Source could have found additional financial incentives as small as $0.60 per MCF ($10/tonne of CO2), the Company would have probably constructed another fifteen projects with new carbon infrastructure of about 400 miles.

Carbon Dioxide Regulatory and Industry Observations

From our operating history and knowledge of CCS, we have a view of how to bridge the gap between 1) the current and expected CO2 capture and storage technology and 2) current and expected sources of vent stack CO2 from power generation and other industries. There are four areas on which to focus: CO2 sources, CO2 transportation, CO2 sinks, and the timing associated with their interplay. We believe the answer to managing the gap is a "step process":

Step 1 – Over the next five years, direct incentives and regulatory influence to accelerate the capture and storage of CO2 from non-power generation industries, where CO2 capture costs are significantly lower (than power generation), which would:

a) accelerate the build-out of a carbon transportation and capture infrastructure today and for later use; and,

b) capture incremental vent stack sources, thus lowering our carbon footprint.

Step 2 – Over the next five to ten years, direct incentives and regulatory efforts toward the infrastructure build-out that would carry CO2 sourced from the power generation industries as the cost of separation and capture is reduced.

Step 3 – Immediately direct regulatory efforts at barriers to developing CCS infrastructure, including, but not limited to:

a) CCS approval as a qualified emission reduction activity for carbon trading (including CCS with EOR, which is the lowest-cost infrastructure build-out and which decreases energy imports), thereby creating an additional revenue source to build out infrastructure;

b) eliminating the risk that CO2 will be classified as a waste product by a government agency, which would inevitably cause a loss of interest in CCS by the energy industry and materially slow the infrastructure build-out; and,

c) emphasizing existing state regulations on underground CO2 management instead of adding potential new and burdensome federal regulations.

It is clear that the long-term geologic sequestration answer to single-point, industrial CO2 emissions capture and storage is in saline aquifers, not EOR projects. That being said, there is a very strong, cost-effective interim answer for the next ten years that employs the oil-based revenues in EOR to subsidize the infrastructure build-out and prepare the foundation of a carbon highway for the next generation of cost-effective CCS in power generation.

Accelerating CCS Infrastructure for Non-Power Generation CO2 Sources

Today, there exist about 3500 miles of CO2 pipelines in North America that transport CO2 to EOR sinks that were built on the back of oil revenues. Today, these CO2 pipelines carry both underground and vent stack-sourced CO2. These same pipelines, when incentivized to carry additional volumes of anthropogenic CO2, will expand the backbone structure of a carbon highway in the US. Expanding these pipelines with assistance from oil-based revenue is the most cost-effective means for any infrastructure growth. Incentives should be aimed at anthropogenic CO2, regardless of processing source, allowing the marketplace to secure the most cost-effective source that adds new pipelines connects to new EOR sinks. We estimate that an additional 2000 miles of anthropogenic CO2 pipelines could be developed over the next five to seven years in the US by providing $10 per metric tonne (approximately $0.60 per MCF) incentives, so long as crude oil values stay above $50 per barrel.

Accelerating CCS Infrastructure for Power Generation CO2 Sources

There appear to be several opportunities for new construction with IGCC and super-amine type retrofits that would combine the resulting CO2 separation and capture with EOR projects. We estimate that incentives necessary to see these types of CCS projects develop are in the range of $20 per metric tonne (approximately $1.20 per MCF) and that such projects would contribute materially to carbon infrastructure build-out. We estimate that these project types, when subsidized by oil-based revenue from EOR projects, would add about 2500 miles of CO2 infrastructure over a period of about ten years.

Accelerating Carbon Market Acceptance and Reducing Regulatory Barriers

Blue Source has sold approximately 9 million tonnes of ghg VERs from geologic sequestration in EOR projects during the last seven years. With the exception of one sale totaling 100,000 tonnes, we believe we have sold all the ghg VERs from EOR sequestration ever sold. During this time, we have heard just about every reason why CCS-based offsets should or should not be included in a carbon offset trading program. Without repeating each pro and con argument here, it appears, fortunately, that markets and regulators are very slowly moving toward an acceptance of these types of emission reductions (whether captured in EOR or in non-EOR projects) once appropriate verification and monitoring structures are in place. Accelerating the market acceptance of the fact that CCS is a valid ghg emission reduction is a direct benefit to the further development of CO2 infrastructure. Regardless of the existing lower carbon market values in the US and the lack of a formalized federal trading structure, the voluntary ghg trading markets that have been active for the last ten years do find value in US-based geologic sequestration of CO2 in EOR offsets. Congress's citing geologic sequestration (with or without EOR) as an official part of its plan to manage the country's carbon footprint would send clear signals to the voluntary and evolving state regulatory markets that value needs to be given to transactions of this type. In a pre-federal, pre-state marketplace, this will not place value so much in the price of a CCS offset as much as it will encourage investors to place more risk capital into this particular project type.

There has been a great deal of discussion about whether or not CO2 should be viewed as a waste product, along with related management and control regulations, and whether it should be regulated at the state or federal level. To the energy industry, this translates into a completely different risk profile when injecting CO2 into EOR or saline aquifers. Today, approximately 2.5 billion cubic feet per day of CO2 is injected into the ground for EOR in this country in the Gulf Coast, the Southwest, and the Rockies. In the last 20 years, a total of approximately 11 TCF of CO2 have been injected into the ground for EOR. To our knowledge, not one single person has been killed as a result of the storage of CO2 in this manner, nor have there been material disruptions in geologic substructure economies. New significant regulatory oversight of an activity that has been conducted safely under existing state regulations for several years would present significant risks of cost increases, delays in capture and sequestration, and exits from the marketplace of qualified players who will elect not to deal in a waste management industry.

Conclusions

We agree that the best long-term answers for CCS in the US involve accessing saline aquifers, developing cost-effective separation and capture technologies for existing and new power generation facilities, and providing for regulatory and economic structures that aid the development of the first two items. The big issue is the time it takes to achieve the best long-term answer. The gap between 1) proven and cost-effective CO2 separation and CCS technology, and 2) the present and expected CO2 emissions, is estimated to be over 20 years. That being said, we believe there are very meaningful steps that can be taken today and over the next ten years that will bridge the gap significantly earlier than currently estimated – steps that materially lower the cost of CCS and that accelerate the benefits of reaching the very best long-term answers. The gap will be bridged in much the same manner as those 3500 miles of existing CO2 infrastructure were developed: by relying on oil-related revenues. But the process will be accelerated by applying regulatory incentives and forces.

United States Senate
Committee on Finance
Subcommittee on Energy, Natural Resources and Infrastructure

Coal: A Clean Future

April 26, 2007 Hearing

215 Dirksen Senate Office Building
Washington, D.C.

Testimony by
Steve Waddington, Executive Director
Wyoming Infrastructure Authority

Mr. Chairman and Members of the Subcommittee, thank you for inviting me to appear before you today. My name is Steve Waddington. I am the Executive Director of the Wyoming Infrastructure Authority (WIA). The WIA is an instrumentality of the state of Wyoming. Our mission is to diversify and expand the state's economy through improvements in the electric transmission grid, and to stimulate the development of advanced coal technologies for electricity production.

The WIA was formed in 2004 by the Wyoming State Legislature. The Legislature provides the WIA with bonding ability and other powers, to promote transmission and advanced generation development in the state and throughout the region. The WIA participates in planning, financing, constructing, developing, acquiring, maintaining and operating electric transmission facilities and their supporting infrastructure. In 2006, the Legislature expanded the WIA responsibilities to also promote advanced coal generation technologies.

Introduction – Two Intertwined First Premises

My testimony today on *Coal: A Clean Future* is based upon two equally important premises. The first premise is that the United States and other governments will take action to restrict the emission of CO_2 and other greenhouse gases. The second premise is that coal will continue to play an indispensable role as a primary source of energy to fuel the economy in the United States and around the world. These two premises are intertwined. Governments and industry must continue to work together to confront the essential challenge of how to continue to use coal to meet energy needs while at the same time mitigating carbon emissions in a cost effective manner. Those who say coal should not continue to be used in a carbon constrained world are wrong or misinformed, as emerging technologies will allow coal to be used to produce clean energy.

New Coal Technologies – The Federal Government's Vital Role

The federal government has a crucially important and large role to play to support the commercial-scale demonstration of advanced coal technologies that capture CO_2. The proper role of the federal government should be to prime the pump for commercial scale demonstrations. These commercial demonstrations should be at a utility scale (250-500 megawatt) and should employ a variety of clean coal technologies. By providing significant financial support to catalyze the investment in emerging clean coal technologies, the federal government will be partnering with the private sector to bring these technologies to the market place.

These clean coal technologies are, by definition, more expensive and technologically risky, compared to conventional coal-fired power plants. As commercial demonstration of these technologies prove successful and a new vintage of clean coal technologies emerge, costs and risks will be reduced and the further need for federal support will diminish. This approach to research and commercial demonstration is not new; in fact, the federal government has played this role for a wide array of technology advancements in the past. In light of the need to address CO_2 emissions, there was never a greater need for federal help to spur clean coal technology deployment than today.

Last week, the Wyoming Authority announced a partnership with a major electric utility – PacifiCorp – to develop an integrated gasification combined cycle (IGCC) commercial demonstration power plant. This will be the first IGCC plant designed and built to use lower-rank western coals at altitudes above 4,000 feet. This groundbreaking project will include both the capture and sequestration of CO_2 and will operate on a long-term commercial basis.

The proposed facility is planned for PacifiCorp's Jim Bridger Plant complex near Point of Rocks, Wyoming. The Bridger site is an existing generating site with four operating coal units. The new 500-megawatt demonstration plant will be designed to utilize Wyoming Powder River Basin coal and other western coals and will meet the other objectives described in Section 413 of the Energy Policy Act to demonstrate IGCC technology at altitudes above 4,000 feet on a commercial scale. The plant is being designed to capture CO_2 that will be sequestered in either a geological formation, or in an enhanced oil recovery environment.

The WIA and PacifiCorp are now seeking significant federal financial support, including appropriations under the provision of the 2005 Energy Policy Act that authorized a western state coal gasification commercial demonstration power plant. An initial appropriation for Fiscal Year 2008 of $50 million is being sought to begin funding this project. Additional requests for appropriations will be made in subsequent years to co-fund the build out of the project. In total, the project is requesting federal appropriations totaling $500 million. The total capital cost of the project is expected to be well over $2 billion.

Adequate federal funding support for the Wyoming Section 413 demonstration plant is but a small step in what is needed to support a clean coal technology program. While IGCC is today a leading candidate for electricity production with CO_2 capture, it is critically important to demonstrate alternative coal combustion and conversion technologies that include CO_2 capture capability. Federal R&D support in this area is crucial. In this emerging technology arena, it is premature to consider IGCC as the exclusive *technology winner*. Other promising technologies under development deserve federal support, such as ultra-super critical oxygen fired coal combustion, and CO_2 separation methods other than gasification.

Sequestration – A Key Enabler

The sequestration of carbon will be a key enabling technology for coal to continue to contribute to the world's energy needs. Today, CO_2 is injected into older oil fields for purposes of enhanced oil recovery. However, sequestration in large-scale geological formations is untested on a commercial level. It is vital that federal R&D in this area continue and it must be accelerated to allow for a better understanding of how CO_2 reacts in various geological environments. Large-scale injections of CO_2 in a variety of geologic formations are required, to characterize the geology and better understand how CO_2 interacts in these storage media.

Here again, federal RD&D support is vitally important. CO_2 geologic sequestration demonstrations are costly. The recent MIT report entitled *The Future of Coal* suggests that the federal government should immediately fund large-scale commercial demonstration projects to test carbon injection under pressure in various geologic media. MIT suggests such tests should be at levels in excess of one million tons per test. Such a commercial-scale effort will certainly cost many millions of dollars, but it is essential that these tests begin now. The Department of Energy through its Regional CO_2 Partnerships (which involves many universities around the country), are engaged in this important work.

Mr. Chairman, your home state of New Mexico is leading the Southwest Regional Partnership for Carbon Sequestration. That effort is being run by the New Mexico Institute of Mining and Technology. The DOE has contributed $1.6 Million to CO_2 sequestration efforts in that region.

Chairman Baucus' state of Montana is leading the Big Sky Carbon Sequestration Partnership, which is being run by Montana State University. The DOE has contributed almost $1.6 Million to that effort. The University of Wyoming is part of both of these regional partnership collaborations. Unfortunately, these regional partnership efforts need much more help from the federal government, if we are to move to a world of sequestering CO_2 in geologic formations. The pace and overall effort on CO_2 sequestration must be accelerated.

There will also be a necessary federal role in indemnifying companies for long-term sequestration liability risks. Liability after injection presents unique challenges due to the scale and permanent duration of the sequestration. A federal back-stop for very long-term and catastrophic liability will likely be required. This layering of commercially available insurances with a federal back-stop is a framework that has worked in the nuclear industry via the Price-Anderson Act. At a minimum, some form of limited liability protection should be considered to shield those who sequester CO_2.

Congress should also consider tax incentives to encourage the private sector to develop and to deploy CO_2 capture technologies that include sequestration. For example, a volumetric tax credit for CO_2 that is permanently stored in a geologic formation, or used in either an enhanced oil or gas recovery environment, could be a significant market-moving incentive. Such a CO_2 tax credit for sequestration could be structured similarly to the Production Tax Credit Congress has provided to induce the development of renewable sources of energy.

As an example, to reduce the costs of developing commercial-scale IGCC technology, why not provide a CO_2 sequestration tax credit to the developers of the first 6-9 commercial scale clean coal demonstration projects? This form of federal support would serve to lower the significant cost differential of an IGCC project with CO_2 capture, versus the cost of a traditional pulverized coal power plant without CO_2 capture.

Mr. Chairman, I would recommend a tax-credit on the order of $20 per ton for CO_2 that is sequestered permanently in a geological formation and $10 per ton if the CO_2 is used in an enhanced oil or natural gas recovery effort. For a 400-megawatt coal fired plant sequestering CO_2 at 80%, this CO_2 tax credit would yield a federal incentive of approximately $.017 per kilowatt hour. Today, wind, solar and geothermal renewable resources receive a production tax credit of $.019 per kilowatt hour.

Mr. Chairman, to develop a clean coal technology program, we will need more than appropriations from the federal government. We will also need creativity to support CO_2 capture and sequestration and I can think of no better way to do so than through the tax code. Congress has used the tax code to help the energy industry develop the resources our nation needs to compete in the global market place. Why not use the tax code to help propel a clean coal technology program that will allow us to utilize our most abundant domestic energy resource, coal, in an improved environmental manner consistent with the emission performance requirements likely to be put in place in a carbon-constrained world? The genius of American technology development will yield the results we need with proper and focused incentives that share the risk of commercialization.

Transmission Investment Requirements

Adequate transmission infrastructure will also be vital for a clean future using coal. This is especially true in the west, where coal plants can be located at or near mine-mouth, producing electricity that is shipped by wire to load centers. One of the significant advantages of mine-mouth coal plants in the future will be that in many cases, these facilities are likely to be proximate to prime sequestration opportunities.

The institutional impediments to adequate transmission investment go beyond the scope of this hearing. Suffice it to say that many western states recognize this as a profound problem and are taking proactive measures to address these issues.

In 2004, Wyoming created the Infrastructure Authority, providing the WIA with valuable tools to catalyze transmission investment, including $1 billion in bonding capacity. Today, five additional Western states have joined Wyoming – including most recently, Mr. Chairman, New Mexico – and at least three additional states are actively considering creating state transmission financing authorities.

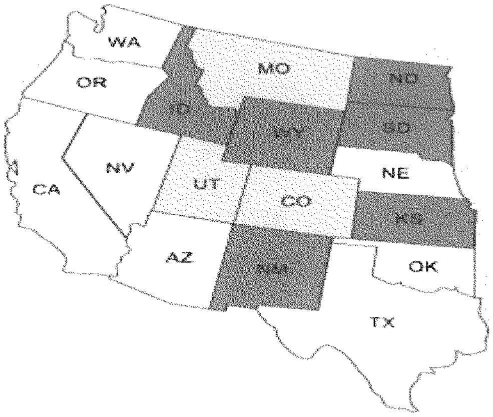


Figure One – States with transmission financing authorities are depicted in green, states actively considering legislation are depicted in yellow.

These western states want to invest in transmission to facilitate energy resource development. Yet under current IRS rules, the bonds of these state entities are not exempt from federal tax. I strongly advocate that this subcommittee consider legislation to relax the so-called *private use restriction* and allow state transmission financing entities to issue bonds for interstate transmission infrastructure development that is not subject to federal tax. This will help to empower states that are trying to make a difference, provide an incentive for needed transmission investment, and ultimately lower costs to end-consumers.

If these state infrastructure authorities were allowed to finance projects using tax-exempt financing, the cost of capital savings of 100 to 150 basis points would significantly reduce the costs of transmission lines to consumers. Today, only government owned utilities can use tax-exempt financing. Congress should expand the availability of tax-exempt bonding by making it available to state transmission financing entities that are issuing revenue bonds to finance interstate electric transmission facilities with voltages of at least 230 kV.

In Conclusion

There is a clean energy future with coal continuing to play an indispensable role as a source of fuel for electricity and other uses. There is a vital role for the federal government to provide matching funds and R&D to support the emergence of advanced coal technologies. Funds to support a Wyoming IGCC plant with CO_2 capture and sequestration under Section 413 of the Energy Policy Act is essential to this commercial demonstration in the West. Much more is needed to support other coal conversion technologies that allow for CO_2 capture. Sequestration will be the key enabling technology and federal support in a variety of ways will be critical to prove large-scale geologic sequestration. Adequate transmission investments will also be key to a clean future using coal and expanded renewable energy like wind and solar. Congress should enact legislation to empower state financing entities to invest in needed transmission infrastructure with tax-exempt bonds.

Mr. Chairman, it is essential that Congress consider the costs associated with addressing climate change. Significant funding support from the federal government is vital for both clean coal commercialization and CO_2 sequestration activities. Congress needs to examine and enact appropriate tax credit support to lower risks and to jump start CO_2 sequestration. These efforts will be costly and a partnership between the private sector and the federal government will be vitally important.

Mr. Chairman, thank you again for the opportunity to testify today. I would be pleased to answer any questions that you or your colleagues may have.

COMMUNICATIONS

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26 April 2007

Honorable Jeff Bingaman, Chair
Subcommittee on Energy, Natural Resources, and Infrastructure
Committee on Finance
United States Senate

Re: Deployment incentives for CCS commercialization

Dear Chairman Bingaman:

Thank you for holding today's hearing on Coal: A Clean Future. I write as a private citizen, from perspectives of public service in energy and environmental policy making,[1] to support a new recommendation of the National Commission on Energy Policy:[2]

> Direct greater resources toward accelerating the commercialization of carbon capture and storage (CCS) by providing substantial deployment incentives. Specifically, the Commission believes CCS projects should be eligible for bonus allowances under a greenhouse gas trading program that are at least equal in value to incentives provided under the renewable energy production tax credit.

Attached is a proposal for just such a deployment incentive in the form of a \$1 per Mcf (or about \$19 per metric tonne) of CO_2 captured and placed into long-term storage – ***including, but not limited to, CO_2 enhanced oil recovery (EOR).***

The National Coal Council spelled out in 2006[3] why CO_2-EOR must fit, seamlessly, into any serious CCS program as the first, critical step – a virtual open sesame – to geologic storage. Indeed, CO_2-EOR "is *the* logical vehicle to build out infrastructure for non-EOR CCS."[4] And CO_2-EOR contributes to energy security:

- Five percent of our domestic production (250,000 barrels of oil per day, mainly in New Mexico and Texas) – displacing an equal amount of imports – while stashing away 10 million metric tons of CO_2 a year.
- Congress should aim for a 10-fold increase. But CO_2 is in short supply

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[1] Retired member, Arent Fox LLP. Administrator, Economic Regulatory Administration of U.S. DOE (1977-79). Deputy Administrator, Federal Energy Administration (1977). Commissioner, NJ Department of Environmental Protection (1974-77).

[2] http://www.energycommission.org/site/page.php?index

[3] *Coal: America's Energy Future*, vol. 1, ch. 6. http://nationalcoalcouncil.org/report/NCCReportVol1.pdf

[4] Bardin, D.J. *Injecting Carbon Dioxide into the Rocks: Prospects and Policies for Enhancing Recoverable Petroleum Resources and Venting Less CO_2 to the Atmosphere*, presented at 10th Cairo International Conference on Energy and Environment [CairoEE10] (March 2007). Copy lodged with the Committee.

- New incentives are needed to bring more anthropogenic CO_2 onto the market.
- Congress can be proud of its past role in putting the USA at the forefront of worldwide CO_2-EOR. This Committee worked on strengthening and targeting incentives during the last Congress, [5] but its proposal was not enacted. Now you have an excellent opportunity to review the issues in the current contexts and select and enact a strong, effective incentives package.
- Our country needs sustained efforts to achieve results over many years.
- During the 10-year scoring period, most stored CO_2 will go into EOR projects that will generate extra revenues to the Treasury (as well as other benefits).
- *Direct* income tax and royalty payments to the Treasury will exceed tax losses.
- Indirect benefits will include job creation, more income to state and local governments and private royalty owners, and a less unfavorable international balance of payments.

"Rifle shot" incentives legislation, this year, to accelerate commercialization of CO_2-EOR (as well as non-EOR storage) will reduce oil imports and build infrastructure for long-term CO_2 storage; it will be compatible with any cap-and-trade, safety valve, or other broader legislation, addressing energy security and climate change issues; it will make any such broader legislation less risky or costly and, therefore, easier to complete.

The attachment specifies key ingredients of a CCS incentive and provides State-by-State estimates of enhanced oil production potentials. Please include this letter and attachment in the printed record of your hearing.

Best personal wishes.

Faithfully,

David J. Bardin

Attachment: ***A carbon dioxide commodity tax credit geared to the USA economy***

c: Honorable Max Baucus, Chair, Committee on Finance
Honorable Charles E. Grassley, Ranking Member, Committee on Finance
Honorable Craig Thomas, Ranking Member, Subcommittee
Editorial and Document Section, Room SD-203

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[5] Joint Committee on Taxation *Description of the "Energy Policy Tax Incentives Act of 2005"*. JCX-44-05 June 14, 2005. http://finance.senate.gov/sitepages/leg/leg061405a.pdf page 24-25 (Enhanced oil recovery credit for carbon dioxide injections).

A carbon dioxide commodity tax credit geared to the USA economy

We propose a commodity tax credit of $1 per thousand cubic feet of captured CO_2, beginning in 2009 (about $19 per metric tonne), for all captured CO_2 that is stored geologically – an inflation-adjusted, free-standing, fully portable credit, not subject to AMT or other reductions.

- This incentive would reward, *but not compel*, industrial capture + long-term storage of CO_2.
- Any technology for storage in geologic formations that the Department of Energy (DOE) recognizes as proven – initially enhanced oil recovery (EOR) and enhanced gas recovery (EGR) [1] – would qualify. Treasury in consultation with DOE would adopt implementing regulations that certify "capture" and "storage" technologies.
- After 2009, Treasury in consultation with DOE would advise Congress whether (a) to raise credit amount or (b) refine eligibility (e.g., minimum efficiency standards).
- State agencies would regulate injection, using or expanding programs that unite governors of 30 States in the Interstate Oil and Gas Compact Commission (IOGCC), a group that has established a carbon capture task force and works with DOE on these issues. See their 2005 report at http://www.iogcc.state.ok.us/issues_carbon.aspx.

Capture of CO_2 and its long-term geologic storage ("sequestration") – CCS – can ▶reduce oil imports by stimulating more EOR and ▶address some climate change issues *compatibly with long-range US interests* as to job growth, coal (with which we generate most of our electricity), other domestic resources, and national security – during decades of energy transitions.

▶ We pay dearly for importing so much oil – partly because **2 out of 3 barrels of domestic crude oil are left in the ground**, on the average.

▶ Injecting CO_2 into suitable oil reservoirs could reap much of this stranded resource bounty and reduce emissions – potentially 46 billion barrels of added recoveries in 21 States and part of the federal offshore domain *based on current state of the art technologies only* (assuming $40/bbl oil prices). That's twice today's USA proved crude oil reserves.

*But with naturally occurring CO_2 in short supply **the USA needs to capture more industrial CO_2**.*

CO_2 capture technologies currently available for electric power plants are expensive and suffer from high energy penalties.

- Recognizing the need to advance capture technology, Congress wisely funds research and development and demonstration projects to improve CO_2 capture and storage options.
- We should continue and expand these RD&D efforts in order to reduce costs and energy penalties so that we may exploit all domestic resources wisely. Robust RD&D protects vital USA interests as to national security, oil imports and the environment.

Less costly capture technologies are now available for other types of industrial plants (e.g., natural gas processing, cement, ammonia and fertilizer plants) that now produce 120 million metric tonnes a year of high-concentration CO_2 – with only 10 million tonnes currently injected into EOR. That leaves 110 million tonnes a year of "low hanging fruit" that a tax incentive could help reap now.

For the long run, planners, researchers, and business communities need assurance of a **permanent *commercialization* incentive for affordable CO_2 capture** so as to provide

▶a significant measure of business certainty and

▶a base for actions that Congress, States, and USA industries may take – **helping support and make more economical the development of advanced CO_2 capture technologies** such as industrial gasification for chemicals and fuels.

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[1] *See* Intergovernmental Panel on Climate Change, SPECIAL REPORT: CARBON CAPTURE AND SEQUESTRATION. 2005

▶ We anticipate that robust RD&D and commercialization tax credits would increase enhanced oil recovery more and more each year – so that, **by 2016, we could reach 750,000 barrels daily** [2] **or 274 million barrels for the year of domestic EOR production** – displacing overseas imports, creating jobs, and generating enough extra revenues for the Treasury to pay for the tax credit.

- Increased revenue to the Treasury during the 2007-2016 scoring period will actually exceed estimated revenue loss if oil prices remain in the $40-50 per barrel range or higher.
- By conventional scoring, tax revenue loss to the Treasury will be zero in 2007 and 2008, rising gradually thereafter, we estimate, to $1.3 billion in 2016 (when we anticipate 60 million tonnes sequestered), for a total of $5 billion over 10 years.
- If Congress decides to offset scored revenue losses, it might weigh some combination of fees, after 2009, on oil imports (now running at about 5 billion barrels a year and rising), liquid transportation fuels consumed (also running at about 5 billion barrels a year, which is 210 billion gallons a year, and rising), and electricity generated by burning fossil fuels and delivered to the grid (about 2,600 billion kWh a year). Such fees (to recover revenue loss only) would be a small fraction of one percent of retail prices of relevant commodities.

▶ Benefits beyond the scoring period (*i.e.*, after 2016) will include less imported oil, more jobs in the USA, more GDP, more income tax and royalty revenues to federal, state and local governments, more favorable balance of payments, and reduced national security risks.

- "Next generation" technologies, now at the RD&D threshold, could add even more.
- By 2030, commercialization incentives coupled with robust RD&D can yield 3 million barrels of EOR oil *daily* (or 1.1 billion barrels *annually* not imported from overseas); and
- 300 million metric tonnes a year of CO_2 placed in long-term, geologic storage instead of emission into the atmosphere. CO_2 injected for EOR reasons has remained in the rocks' pore fluids in practice; called "incidental storage" it builds a foundation for broader CCS.
- And we will further advance technologies for clean use of abundant resources such as coal.

Follow-up legislation and/or contract arrangements could address issues of responsibility and ownership after injection into a geologic formation has ended (as well as harmonizing provisions of federal and state statutes in respect to future technologies for non-EOR, non-EGR storage).

▶ Congress can achieve such win-win-win results by enacting a commodity tax credit alone. If Congress adds a cap-and-trade or other measure aimed at carbon emissions on top of a tax credit, such added measures would cost American consumers less and carry less risk of shifting American jobs overseas because an underlying commodity tax credit would shoulder part of the burden.

Issues Congress must decide:

▶ whether to award the portable tax credits initially to the capturing entities (electric utilities, rural coops, chemical plants, hydrogen plants, cement plants, etc.) or to the storing entities;
▶ whether tax, royalty revenues from increased EOR production will fund early ("scoring") years;
▶ whether to differentiate CO_2 being shipped to existing Canadian or USA EOR projects.

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[2] Today's EOR production is about 250,000 barrels daily (about 5 percent of domestic production).

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Potentials for Enhanced Oil Recovery from the Major Oil Reservoirs in 22 States -- Adding Economically Recoverable Resources by Using Today's State-of-the-Art

(a) Original Oil in Place (OOIP) in major oil reservoirs amenable to CO_2-EOR, (b) Oil being stranded with current practices, (c) Potential for incremental oil by widespread use of current state of the art CO_2-EOR *assuming ample supplies and low costs of CO_2*, oil prices of $40/bbl, and a 15% rate of return hurdle.

	(a)	(b)		(c)		(d)
	OOIP "Endowment"	Oil **stranded** if no extra CO_2-EOR		**Added** oil with State-of-the-Art CO_2-EOR		
STATE	Resources Millions/bbls	Resources Millions/bbls	% of OOIP	Resources Millions/bbls		Production Bbls/year*
Alabama	800	300	37.5%	110		2,750,000
Alaska: North Slope	62,200	41,900	67%	7,600		190,000,000
Alaska: Cook Inlet	3,100	1,800	58%	140		3,500,000
Arkansas	4,000	2,800	70%	230		5,750,000
California: San Joaquin Basin	39,500	25,400	64%	1,780		44,500,000
California: Los Angeles Basin	22,900	16,600	72%	1,370		34,250,000
California: Coastal Basins	12,400	9,300	75%	830		20,750,000
Colorado	3,500	2,100	60%	580		14,500,000
Florida	1,300	800	61.5%	30		750,000
Illinois	6,900	4,200	61%	460		11,500,000
Indiana	700	500	71%	50		1,250,000
Kansas	11,300	7,900	70%	1,220		30,500,000
Kentucky	1,700	1,300	76%	40		1,000,000
Louisiana onshore	16,100	9,400	58%	1,520		38,000,000
Louisiana offshore: State waters	3,600	2,200	61%	200		5,000,000
Louisiana offshore: shallow federal waters **	24,500	13,500	55%	3,400		85,000,000
Michigan	1,400	900	64%	80		2,000,000
Mississippi	1,900	1,200	63%	230		5,750,000
Montana	5,100	3,600	71%	110		2,750,000
Nebraska	800	500	62.5%	40		1,000,000
New Mexico: Permian Basin	13,100	9,200	70%	1,040		26,000,000
North Dakota	4,100	3,000	73%	390		9,750,000
Oklahoma	36,800	27,500	75%	4,740		118,500000
South Dakota	100	30	-	0		0
Texas: Permian Basin	57,100	36,100	63%	9,720		243,000,000
Texas: Central	24,700	19,000	77%	1,330		33,250,000
Texas: East	20,000	11,900	59.5%	3,480		87,000,000
Texas: Gulf Coast	23,000	13,900	60%	3,750		93,750,000
Utah	4,100	2,900	71%	740		18,500,000
Wyoming	15,200	10,400	68%	1,112		27,800,000
IOGCC member States not assessed: Arizona, Ohio, Maryland, Nevada, New York, Pennsylvania, Virginia, West Virginia **						

* "Bbls/year" entries assume all EOR resources will be produced over the same 40 years in equal amounts (without build up).

** DOE funding for assessments did not cover federal deep offshore or the eight other Interstate Oil and Gas Compact Commission (IOGCC) member States.

Source: Department of Energy, Office of Fossil Energy, Ten Basin Assessments Prepared by Advanced Resources International (2005, 2006), Scenario #4 [http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html] – except that col. (d), "Bbls/year" production = col. (c) / 40, as noted above, calculated for rough, illustrative purposes.

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Comments by The Clean Air Task Force (CATF)
Submitted to the Subcommittee on Energy, Natural Resources, and Infrastructure
of the Senate Committee on Finance

April 26, 2007 Hearing on Coal: A Clean Future

Introduction

Founded in 1996, CATF is the only major national environmental advocacy organization with an exclusive focus on protecting the Earth's atmosphere and human health from air pollution and climate change. This singular focus enables CATF to field deep analytic and strategic resources equal to the significant and complicated atmospheric challenges we face over the next fifty years.

Over the past several years, one of CATF's major activities has been to work with state and regional environmental groups, state governments and private project developers in several parts of the country to facilitate early domestic deployment of coal gasification technology – with carbon capture and geologic sequestration (storage) where currently feasible. We have briefed numerous Congressional offices – accompanied by state environmental partners -- about the promise of coal gasification technology. Another related CATF focus has been exploring how to remove barriers to promising advanced coal gasification and carbon capture technologies that have not yet entered the market. This "hands on" project facilitation and market entry work provides us with a useful perspective on what is happening on the ground in today's marketplace.

In these comments, we will briefly restate the importance of moving forward radically cleaner coal technology than is deployed today; highlight current market developments on the ground which the subcommittee may not be aware of; and, finally, discuss key challenges to radically cleaner technology, and what the federal government might do to help tackle those challenges.

I. The Current and Projected Environmental "Footprint" of Coal

Coal-fired power generation is today one of the planet's most environmentally destructive activities. It is responsible for most of the nation's sulfur dioxide emissions that, even after recent regulatory reductions, will still take 15,000 lives prematurely in the

US each year by EPA's own estimate. It contributes substantially to nitrogen oxides, which add to smog, haze, and crop and ecological damage. It emits most of the nation's manmade mercury air pollution. Current coal mining practices have scarred land and threatened water and habitat. Coal power generation consumes and discharges enormous quantities of water, while generating nearly 100 million tons of toxic wastes each year, the disposal of which is not regulated by the federal government. Finally, coal power generation is responsible for nearly 40% of the planet's man-made emissions of carbon dioxide that contribute to global warming.

Despite these problems, coal fired power generation is likely to be relied on for decades to come and is projected to expand dramatically. World electric demand is expected to triple by 2050, coming largely from developing countries like China and India. Most analyses agree that this underlying demand growth will substantially outpace even the most aggressive energy efficiency policies. Renewable energy, while it should and will be widely deployed, faces significant physical, environmental and economic challenges that will practically limit its share of total electrical supply for several decades. Natural gas is relatively expensive and its reserves are far more limited than coal. Finally, nuclear power faces considerable hurdles of scale, economics and environmental opposition. For these reasons among others, China is building as much new coal capacity each year as the entire UK power grid and coal power generation in India is projected to grow rapidly - matching current US coal consumption by 2020 and China's current coal consumption by about 2030. The United States faces both growing demand for electricity and an aging power plant fleet; coal will remain economically attractive to meet some portion of electricity demand growth and to replace some existing power plants.

Turning to climate, numerous analyses performed or commissioned by such bodies as the Intergovernmental Panel on Climate Change, the European Union, the National Commission on Energy Policy, academic institutions such as Harvard, MIT, and Princeton University as well as environmental organizations such as Friends of the Earth-UK have concluded that, even with aggressive energy efficiency, renewable energy development and in some cases nuclear expansion, coal fired power generation is likely to remain a significant part of any 2030-2050 global power supply. Accordingly, each of these studies has identified the critical importance of transitioning coal use to technologies that minimize health-related air emissions and allow for the removal and storage of carbon dioxide, and to begin to demonstrate and scale up those technologies on a commercial basis as soon as possible.

In short, the planet is unlikely to be able to live *without* coal for some time to come. But, at the same time, the planet, from an environmental standpoint, can't stand to live *with* coal as it is currently used to produce electricity. This leaves only one path forward: we need to change how we *use* it – and we need to do so as quickly as possible.

II. What Is to Be Done?

An environmentally responsible coal policy would do the following:

- ✓ Ban the construction of new coal combustion plants due to their inherently unacceptable air, water, solid waste and climate impacts.
- ✓ Rapidly commercialize the use of integrated coal gasification combined cycle (IGCC) for electric power generation, because it has a much smaller environmental footprint for air emissions and waste than does coal combustion.
- ✓ Rapidly demonstrate the feasibility of large-scale geologic storage of carbon dioxide and then require all new coal power plants to capture and sequester at least 90% of their coal carbon content.
- ✓ Demonstrate and deploy advancements such as underground coal gasification, that could further shrink IGCC's environmental footprint by substantially minimizing mining impacts and waste management
- ✓ Reform coal mining practices worldwide, impose effective federal regulation of coal plant solid waste disposal and reduce coal generation water use and associated impacts to the minimum practical levels.
- ✓ Increase the energy efficiency of IGCC power generation to the maximum practical levels over time.
- ✓ Establish effective carbon dioxide emissions controls.

Commercializing IGCC is of special importance. Because it is an inherently cleaner process – the gas it produces from coal must be free of most contaminants to power a gas turbine – IGCC reduces deadly sulfur and nitrogen oxide emissions to very low levels – approaching those achievable by natural gas combined cycle power plants. Gasification is the *only* coal power generation technology that can virtually eliminate mercury air emissions and capture most of the coal mercury content in a concentrated form that can potentially be sequestered from environmental release; IGCC is the only way we can continue to use coal to produce power without adding significantly to the global mercury burden. Total solid waste from gasification is typically half the volume generated by conventional coal plants and gasification water use is substantially lower as well.

Underground coal gasification (UCG), a promising further advancement in IGCC would gasify the coal directly within the deep, unmineable coal seams. This process can potentially eliminate the environmental impacts of current coal mining and transportation practices, as well as significantly reduce the challenges of coal waste management.

Finally, IGCC is the key enabling technology for capture and storage of carbon dioxide from coal power generation and will be essential to meeting any reasonable climate stabilization target. While it is possible to retrofit a coal combustion plant with carbon capture technology, it is expensive and inefficient to do so today, costing twice as much for plants using bituminous coal as capturing carbon from an IGCC plant and reducing plant efficiency by as much as 40%. While development of more cost-effective coal-combustion carbon capture alternatives is important, current efforts are very early in the technology development stage, and it is unclear whether and when cost-effectiveness will be fully demonstrated for this technology. *If we are to turn the world coal tide to a near-zero carbon footprint in the next 20 years, IGCC power generation is likely to be the most availing path forward based on current information.*

III. Recent Market Developments

The good news about cleaner coal power and carbon capture is the many recent coal gasification market developments, nearly all of which are too new to be reflected in academic studies and many of which are being conducted by companies not well represented by Washington trade groups or research organizations. When we "look out the window" at these market developments, we see a substantially different situation than is typically presented in available studies or by traditional institutions.

Key highlights include the areas listed below. It should be noted that the coal gasification market developments described below do not reflect a complete survey of recent developments, but rather are intended to illustrate the contrast between the relatively static and out-of-date study characterizations of coal gasification technology with today's rapid pace of market development.

Emergence of new "full system" IGCC vendors

Prior to last summer, GE was the sole "full systems" IGCC vendor capable of offering all major IGCC components (that is, gasifier, combustion turbines and steam turbines) in a single package. Since that time, Siemens and Mitsubishi have developed full system commercial IGGC offerings, significantly expanding vendor choice for potential IGCC project developers. Siemens emerged as a full systems vendor last summer when the company acquired the Future Energy gasifier. NRG's recent selection of Mitsubishi as the technology supplier for their proposed domestic IGCC plants introduced the entry of Mitsubishi as a full systems vendor.

Emergence of new coal gasifiers

Up until last summer, there were only three serious commercial coal gasifier offerings: the GE (Texaco technology), ConocoPhillips (E-Gas technology) and Shell gasifiers. These gasifiers have different characteristics that affect their suitability for various coal types, with Shell appearing most suited to low-rank coals (sub-bituminous and lignite). These gasifiers are also estimated to vary significantly in cost. Nearly all IGCC studies and academic literature have been restricted to analysis of these gasifiers.

Several additional coal gasifiers have moved into the marketplace over the past year:

- The *Future Energy* gasifier, developed in the former East Germany and recently acquired by Siemens, should be well suited to low rank coals and shows promise of being quite economically competitive.

- The *British Gas Lurgi* (BGL) gasifier is an evolution of the Lurgi gasifiers used extensively in South Africa and at the Dakota Gasification plant in the US. This gasifier should also be well suited to low-rank coals.

- The *Mitsubishi* gasifier is partially oxygen blown, should also be well suited to low-rank coals and shows promise of being quite economically competitive.

As all three of these gasifiers are well suited to low-rank coals, they provide a much more competitive set of market offerings for projects using these coals and should reduce pre-inflation low-rank coal IGCC project costs. This point is particularly important as some critics have suggested that some conventional gasifiers are not well-suited to low rank coals may not be an economic path for low-rank coal use.

"Next Generation" IGCC plant development

At least four "next-generation" IGCC projects are moving forward in the US, in addition to the "hybrid" coal gasification plants described below. These projects are AEP's Meigs plant in Ohio and Mountaineer plant in West Virginia, Duke Energy's Edwardsport plant in Indiana and BP's Carson Refinery Hydrogen project in California.

These projects all use the most advanced available combustion turbine (for example, GE's 7FB) and are a major "scale-up" from the several IGCC plants built at refineries in Europe about five years ago and are much larger than the two early demonstration plants built in the US (Wabash Station in Indiana and Polk Station in Florida) about a decade ago. These projects will typically have about 600 MW of generating capacity. The BP Carson project will use petroleum coke (a coal-like refinery waste product) and will include 90% carbon capture, which reduces plant output to about 500 MW. The BP Carson project will be the first commercial project in the US to include and demonstrate "full" carbon capture.

Several additional "next-generation" plants may also be moving forward, but at a slower pace, including additional AEP-proposed plants in Kentucky and NRG's proposed Huntley plant in New York State.

These "next generation" plants are important for several reasons, including lower inflation adjusted costs and higher operating efficiencies. They also are driving significant detailed engineering design work, including in the case of Duke and AEP serious engineering analysis of options for adding carbon capture to these plants at some future time and provisions that can economically be built into the initial plant to facilitate carbon capture retrofit. The good news is that this very significant amount of engineering work will provide much more detail than is currently available on next generation costs, performance and carbon capture retrofit feasibility. The bad news is that this information remains proprietary and is not yet available in open literature.

"Hybrid" Projects

Some independent IGCC project developers like the ERORA Group and Summit Power are developing coal gasification projects that produce both electric power and substitute natural gas, typically allocating about 50% of the project coal syngas to each of these products. The ERORA group is developing projects in Illinois (Taylorville) and Kentucky (Cash Creek) and Summit Power is developing projects in Oregon and Texas.

These developers are pursing "hybrid" projects because they have economic advantages over next-generation "power only" IGCC plants, including reduced overall project cost, high availability – particularly in projects using several of the new Siemens gasifiers and attractive overall project economics for power generating companies that have existing natural gas power plants by allowing them to have coal based fuel pricing for both their new coal generation and some portion of their existing natural gas generation.

Some of these projects are close to final permitting and full financing. Several projects plan to include some carbon capture and will initially use the captured carbon for enhanced oil recovery (EOR). At least one project is exploring full carbon capture and sequestration. In many respects these projects reflect efforts by project developers to overcome current economic barriers to stand-alone IGCC plants.

Advanced Coal Gasifiers

Several innovative coal gasification technologies are conducting process demonstrations and could be commercially available within the next two years. Two examples among several such systems being developed include Great Point Energy's catalytic coal gasifier (a technology originally explored in the 1970's) and Texas Syngas' molten metal bath gasifier. Both technologies can potentially be produced modularly in a factory and both appear to have potential to reduce gasification costs compared with traditional gasifier designs.

Underground Coal Gasification

Underground coal gasification ("UCG") is just beginning to be recognized as a potential option for utilizing coal. UCG is a gasification process conducted in deep coal seams. Injection and production wells are drilled into the coal seam and are then linked together. Once linked, air and/or oxygen is injected and the coal is ignited in a controlled manner to produce hot, combustible coal syngas that is captured by the production wells, brought to the surface and cleaned for power generation and/or production of liquid hydrocarbon fuels or substitute natural gas. This technology has been used at a minor level since the early 1900's and DOE conducted many pilot UCG projects in the 1970's.

A successful modern pilot project was conducted about six years ago in Chinchilla, Australia by the Ergo Exergy Technologies, Inc. and the first modern commercial UCG electric power production project started up this January in Mpumalanga, South Africa. We also understand that two commercial UCG projects producing hydrogen for chemical plants have been developed in China. The GasTech Company is developing the first North American pilot UCG project in Wyoming. The initial GasTech project will be conducted in the Powder River basin and will use a coal seam 950 feet deep. Current estimates are that the *pre-clean-up* syngas will be produced for about $1.90/mmbtu (as compared with current US gas forward prices of about $8.00/mmbtu for the next several years).

UCG technology is potentially quite significant for several reasons:

1. It can avoid most of the adverse environmental impacts associated with coal mining and transportation;
2. It leaves coal residuals (ash and some other constituents) underground;
3. It can potentially reduce coal gasification costs – perhaps significantly; and
4. It can open up large amounts of deep coal reserves that are currently not economic to mine. Lawrence Livermore National Laboratory (LLNL) estimates that UCG could potentially triple domestic economic coal reserves.
5. Carbon capture costs may be somewhat lower than with above-ground gasification and a significant fraction of captured carbon can potentially be stored in the underground gasification cavities created by a UCG project.

Once this technology emerges from the pilot/demonstration stage, which will be necessary to clarify technology costs, it may be deployed rapidly if it proves to be more economic than conventional pulverized coal plants or advanced above-ground gasification system IGCC's. LLNL has recently produced a summary of current UCG knowledge that is available at https://eed.llnl.gov/co2/11.php.

IV. A Key Technology Gap

Developing a practical and very-low cost method of capturing carbon dioxide from existing power plant flue gases would be an enormous boost to global efforts to reduce carbon dioxide emissions and may be the only practical opportunity to significantly reduce future carbon dioxide emissions from the rapidly developing coal power plant "fleet" in China and India. Current technologies that can accomplish this task are too expensive and consume far too much energy to be practical to apply broadly throughout the world. While current research in this area is focused primarily on what are essentially incremental improvements in existing technology systems, a "break through" technology is needed. Potential "high-risk/high-reward" breakthrough technologies, like structured fluids, have been identified (in this case by MIT researchers) but there appear to be no relevant sources of Federal support for such research.

V. Challenges to Advanced Technology Deployment

Several problems are constraining rapid deployment of advanced coal gasification technologies and associated carbon capture, including the recent substantial increase in large energy project costs; the lack of an economic incentive to build IGCC projects with full carbon capture today; and Federal advanced coal research, development and deployment programs that are not adequately funded or sufficiently broad.

Recent large energy-project cost inflation

For several reasons, including massive infrastructure development in China and very large investments in Persian Gulf oil and gas projects, the construction cost of large energy projects has significantly increased over the past two-to-three years. In some cases, this cost inflation may have *doubled* project costs – including some domestic proposed coal plants. While it is not clear how long costs will continue to rise or for how long they will remain inflated, it does not appear that this cost-inflation period will be short.

The current cost-inflation environment will also affect the economics of carbon capture and sequestration for new coal projects, raising the estimated costs from roughly 1.5 cents/kWh to about 2.5 cents/kWh. This suggests that if this cost environment prevails, carbon capture will begin to be economic at a carbon emissions price of about $40 per ton of CO2, at least initially.

No economic incentive to build new coal plants with full carbon capture today

While the technology exists to develop new coal IGCC plants with full carbon capture and sequestration today, as is being demonstrated by BP's Carson project, there is no economic basis to do so except possibly in the very few cases (like BP's Carson project) where all captured carbon can be used for enhanced oil recovery. This disincentive to adding CCS to new coal plants will continue until captured and sequestered carbon is worth roughly $40/ton of carbon dioxide.

Limitations of Federal Advanced Coal Research, Development and Demonstration Programs

We have not conducted a serious review of the relevant Federal "clean coal" research, development and demonstration programs, but we have observed several "disconnects" between such programs and both promising market activity and needed "breakthrough" technology. We note that all EPACT financial support for new IGCC projects has been awarded to next-generation commercial IGCC projects, which in nearly all cases are being proposed by large investor-owned utilities. In contrast, no innovative "hybrid" IGCC/SNG projects being developed by independent project development companies were awarded financial support. We also note that none of the promising advanced coal gasifiers being developed that we are aware of are receiving significant DOE support nor are these advanced gasifier concepts listed in the various technology evolution "road maps" developed by DOE and others. And as we noted above, no Federal programs exist today that would provide financial support for new IGCC project developers seeking to include full carbon capture and sequestration in their projects.

MIT's Future of Coal Study reviewed current DOE clean coal research, development and demonstration programs and outlines one approach to expanding and better targeting these programs. We see MIT's proposals as a good starting point for discussion, but believe they would not be sufficient to address all research, development and demonstration gaps or "disconnects" we have observed.

VI. What can the Federal Government Do to Accelerate Deployment of Needed Technology?

Several Federal actions could accelerate development and deployment of the advanced coal technology needed to address climate change and dramatically reduce coal's environmental impacts:

1. Establish a production tax credit or some other form of equivalent financial incentives for new coal power plants with full carbon capture and sequestration. These incentives would be in effect until a national carbon emissions reduction program has been established that creates a carbon emissions allowance price sufficient to offset carbon capture and sequestration costs. At current energy project pieces, such a production tax credit would likely need to be at least 2.5 cents per kWh.

2. Establish a carbon emissions performance standard at some future date for new fossil power plants that would require significant carbon capture and sequestration for new coal power plants.

3. Establish effective carbon emissions controls. And,

4. Significantly expand and broaden DOE's advanced coal research development and demonstration programs.

The recent MIT Future of Coal Study outlines one approach for expanding DOE's advanced coal programs and suggests that such programs need to be funded at levels as high as $800-$900 million per year. Beyond MIT's recommendations, it would be useful to review current research and market activity in this field to identify promising technologies that are slipping through the cracks in current DOE programs to help develop more effective programs. It is also critically important that appropriate support be establish for developing "breakthrough" technology in critical areas like practical, low cost carbon capture at existing power plants.

In summary, we believe that the technology we need to transition coal use to much more environmentally sustainable systems could be either deployed or developed promptly if effective Federal advanced coal technology policies were implemented.